Docket:	:	A.14-06-014
Exhibit Number	:	ORA-101
Commissioner	:	M. Florio
Admin. Law Judge	:	S. Roscow
ORA Project Mgrs.	:	L. Tan, C.Chan
ORA Witnesses.	:	Willis, Irwin Fagan/Luckow Lasko, Chan, Tan and Morse

Office of Ratepayer Advocates
California Public Utilities Commission

Testimony on Southern California Edison's 2015 General Rate Case Phase II

San Francisco, California
February 13, 2015

MEMORANDUM

This testimony was prepared by the Office of Ratepayer Advocates ("ORA") of the California Public Utilities Commission ("Commission") in response to the Phase II General Rate Case Application of Southern California Edison ("SCE"), A.14-06-014.

ORA's report examines and calculates marginal costs, which exert a significant impact on the revenue allocation process. If ORA's proposed marginal costs are adopted, the revenues allocated to be collected from the residential class would decline by 0.8% and revenues for small commercial customers on schedule GS-1 would decline by 10.6%.

ORA examines a few residential and small commercial rate design issues, while most residential rate design issues are under consideration in the residential rate design OIR, R.12-06-013. ORA opposes SCE's proposal to establish separate baseline allowances for all-electric customers living in single-family homes versus multi-family homes. ORA supports SCE's proposed delay in the transition date for defaulting small commercial customers to Critical Peak Pricing ("CPP") rates and placing all of them on CPP lite rates. However, SCE should provide customers with enhanced, measurable, and goal oriented outreach and education such as what the Commission required for Pacific Gas and Electric Company ("PG&E") in D. 10-02-032.

Lee-Whei Tan and Cherie Chan served as ORA's project coordinators in this proceeding. Noel Obiora is ORA's counsel. Chris Danforth (Program and Project Supervisor) and Mike Campbell (Program Manager) oversaw this project and the review of this testimony.

List of ORA Witnesses and Respective Chapters

Chapter 1	Marginal Customer Cost	Dan Willis
Chapter 2	Marginal Distribution Demand Cost	Louis Irwin
Chapter 3	Marginal Energy Costs and LOLE Allocation Among TOU Periods	Bob Fagan/Patrick Luckow
Chapter 4	Generation Capacity Costs	Yakov Lasko
Chapter 5	Revenue Allocation	Cherie Chan
Chapter 6	Residential Rate Design	Lee-Whei Tan
Chapter 7	Small Commercial Rate Design	Peter Morse
Appendix A	Statement of Qualifications	All

CHAPTER 1

MARGINAL CUSTOMER COSTS

DAN WILLIS

TABLE OF CONTENTS

CHAPTER I
MARGINAL CUSTOMER COSTS
DAN WILLIS

I. SUMMARY AND RECOMMENDATIONS

Marginal customer costs are those distribution costs that vary with the number of customers in a given customer class, and do not vary by the customers' usage or peak demand. Marginal customer costs can be characterized by determining what costs change if the utility adds a customer, and are identified separately for each rate group.

Within marginal customer costs are the capital costs of customer connection (or "hookup") equipment, together with customer services and operations and maintenance ("O&M") costs, including billing, customer inquiry, and meter reading. The method chosen to estimate hookup costs greatly influences the resulting marginal costs. Under Southern California Edison's ("SCE") proposed method, most of the marginal customer costs are composed of hookup costs, whereas under ORA's proposals, the majority is composed of customer services costs.

In summary, ORA recommends the following:

- <u>Hookups</u>: ORA uses the New Customer Only ("NCO") method instead of SCE's Real Economic Carrying Charge ("RECC"), or "rental," approach when computing marginal customer access costs so as to better reflect the costs that each customer class will cause SCE to incur as a result of adding new Transformer, Service Line and Meter ("TSM") equipment.
- <u>Customer growth</u>: ORA adjusts SCE's forecasted growth levels by averaging them with recorded new connection levels for each rate group.
- <u>Replacements</u>: ORA proposes to reflect replacement of TSM equipment only as a lifetime adder on new connections, recognizing that the commitment to replace hookup equipment is made when that equipment is first installed and that replacement of existing hookups is not a marginal cost.

These recommendations result in the marginal customer costs shown, alongside SCE's marginal costs, in Table 1-1 below.

TABLE 1-1: ORA'S AND SCE'S MARGINAL CUSTOMER COSTS ($ANNUAL)

Rate Group	SCE Hookup Capital	Customer Services	SCE Total[1]	ORA Hookup Capital	ORA Total
Domestic	114.33	33.88	148.22	15.63	49.52
GS-1	182.10	39.65	221.75	21.58	61.23
TC-1	215.84	37.65	253.48	20.75	58.40
GS-2	1,611.70	194.87	1806.57	290.52	485.39
GS-3	2,684.68	974.89	3659.58	165.94	1140.84
TOU-8	4,264.95	1,006.23	5271.19	257.61	1263.84
AG&P <= 200 kW	1,118.77	156.66	1275.42	100.58	257.24
AG&P > 200 kW	2,581.07	853.90	3434.97	351.08	1204.98
Street Lights	118.97	37.18	156.15	9.36	46.55

ORA does not change SCE's customer services costs but makes various comments about SCE's methods in Section III.D below.

II. APPLICANT'S PROPOSALS

As SCE explains in Chapter 2 of its testimony:

> The starting point for calculating marginal costs is the identification of cost drivers, that is, those fundamental aspects of customer electricity requirements that directly cause SCE to incur costs. Next, marginal costs are calculated for small changes in each cost driver, by dividing the change in total cost by the change in the cost driver.[2]

[1] Errata to SCE Exhibit 2 Workpapers, 1/21/15.

[2] SCE-02, page 5 ll. 8-11.

For both customer hookup equipment and customer services costs, SCE identifies the number of existing customers as the cost drivers, and assigns each rate group a unique marginal cost value.

In order to estimate the TSM capital cost portion, SCE conducts "typical customer cost studies" for each rate group. SCE explains, "The typical customer cost studies identify facilities directly associated with the customer interconnection, such as the meter, service drop, protection equipment, and final line transformer."[3] The results of each rate group's study are the sum of these components including loaders, multiplied by an RECC factor which, as explained in the next section, SCE uses to convert capital investments into annual costs for marginal cost purposes.

For estimating customer services costs, SCE states, "We identify the specific activities and assets directly attributable to providing the particular services and then calculate the associated marginal costs. These marginal costs are calculated by customer type and size."[4] Each customer groups' yearly customer service costs are then added to their respective weighted TSM costs (based on SCE's RECC method) to arrive at the total marginal customer costs.

III. DISCUSSION & ORA'S PROPOSALS

A. Support for New Customer Only Method

SCE's proposed method for computing the hookup portion of customer marginal costs, the RECC or "rental" method, has been rejected in five Commission decisions dating back to 1992. The use of this method overestimates the capital cost component of marginal customer costs because it both assumes that hookup costs are recoverable over the life of the equipment and relies on unrealistic conditions that would prevail in a competitive rental market.

---

[3] SCE-02, page 16 ll. 6-8.

[4] *Ibid*, ll. 17-19.

ORA proposes, instead, to use a modified version of the NCO method that the Commission has adopted in nearly all proceedings since 1992 in which marginal costs were litigated. For the following reasons, ORA finds that the NCO method captures customer-related marginal costs more accurately than does the rental method.

1. Background

Key to marginal cost ratemaking is capturing the change in utility costs associated with a small, measurable change in the service required. For marginal customer access costs, only changes in the number of customers affect the level of costs SCE incurs. However, for customer connection capital costs, the costs SCE incurs in adding a customer are typically much higher than the costs it would avoid by losing a customer. In other words, these costs are not symmetric, because the equipment often is dedicated to individual customers rather than shared.

For over 20 years, the Commission has defined customer connection costs as consisting of meters, service drops, and final line transformers ("FLT"), the latter serving as the boundary between customer-related and demand-related distribution. When a customer is newly connected to the distribution grid, establishing that connection usually requires all three of the above elements, often termed "TSM" equipment. If, however, a previously occupied customer premise is abandoned, (or a customer chooses to go "off-the-grid" and surrender his connection equipment), only a fraction of the original TSM cost can be recovered by salvage and/or reuse of the meter and FLT. Similarly, if a portion of a utility system is sold (e.g., to a municipal utility district), the selling utility will likely receive only a fraction of the current replacement cost of the facilities. Thus, the costs of adding a customer and the costs avoided by losing a customer are not symmetric. This lack of symmetry, over time, has led to opposing views on how to best estimate marginal customer costs. SCE proposes to use the RECC method, which treats TSM costs as if they were always fully recoverable at their replacement cost new ("RCN") value, regardless of their age or level of depreciation. ORA recommends the more appropriate NCO method, which includes as marginal only TSM equipment costs for serving new customers.[5]

2. Critique of SCE's Rental Method

ORA opposes the rental, or RECC, method because, unlike the NCO method, it treats none of the TSM costs as sunk and all of them as marginal, while also valuing the equipment at its full RCN value. Since deciding PG&E's 1993 GRC, the Commission has consistently rejected the RECC method in favor of the NCO approach, finding that the RECC method overcharges customers for the cost of their TSM equipment. This has the effect of overstating the role of connection costs in revenue allocation and skewing costs to small customers.

SCE explains its rationale for employing the RECC method in its testimony:

> Assuming electricity customers value the service they receive, the charge should be the same regardless of the age of the equipment. Therefore, the proper charge can be calculated for both existing and new customers by applying the RECC to the current cost of the equipment.[6]

In effect, the RECC results in annual payments that rise with inflation and collect the associated revenue requirement over the life of the equipment. Mechanically, this means that the results of SCE's "typical cost studies" for TSM equipment are multiplied by the RECC value in order to determine a yearly marginal cost to be charged to all existing customers.[7]

This makes sense only if one assumes that the economic value (or opportunity cost) of old equipment is the same as that of new equipment. SCE's concept of "age-indifference" most certainly does not apply, however, to most

---

[5] Section B.2 explains ORA's proposal for dealing with TSM replacement costs as part of the NCO calculation.

[6] SCE-02, pages 18-19.

[7] In contrast, ORA's NCO calculation results in multiplying the TSM hookup costs by the percentage of new connections that will be required each year.

utility distribution plant, including customer hookup plant, for the following reasons:

- There is no active rental or resale market for electric utility customer hookup equipment.
- Once installed, a large part of the costs of customer hookup equipment is sunk. Labor costs of the installation are typically capitalized and cannot be recovered if equipment is salvaged.
- Utilities, when selling their distribution systems, do not price them at the cost of new facilities (their RCN value). Much as they might like to price at RCN, no buyer would pay that amount.

In sum, the rental method would charge customers the full price of new facilities for the use of existing facilities on which they have already paid years of depreciation expense. Thus, the RECC methodology ignores both sunk costs and economic depreciation associated with existing facilities.

Furthermore, SCE argues that, by including only the costs of new connections, the NCO method "ignores the economic value of existing interconnection facilities."[8] However, what both SCE and ORA are attempting to accomplish is to base rates on *marginal cost*, not on a measure of "economic value." The NCO method is a better approximation of the marginal cost of TSM equipment by focusing on those connections required to service new customers. Even if one were to accept the use of an economic value for this purpose, that value certainly would not be RCN when no buyer would pay that amount in the sale of distribution systems.

3. Commission Precedence for the New Customer Only Method

In adopting the NCO method, the Commission, on several occasions, has judged that it better reflects cost causation for TSM equipment. Since 1992, the Commission has consistently found that the RECC method (applied to customer

[8] SCE-02, page 20 line 4.

hookup equipment) overstates costs. For example, in 1996, the Commission made the following Findings of Fact:

> 37. The rental method does not produce a competitive price for customer hookups and, in fact, significantly overstates the price that would prevail in a competitive market.
>
> 38. Under the rental method, and the associated RECC assumptions, Edison's marginal customer costs exceed the cost of hooking up new customers, installing replacements and covering the variable expenses for all customers.[9]

These findings are consistent with Commission findings in Decisions 92-12-057, 95-12-053, 97-03-017, and 97-04-082 spanning both gas and electric utilities and including PG&E, SCE, SDG&E, and SoCal Gas. While these decisions are dated, they are among the most recent Commission decisions that addressed marginal cost issues.

B. Adjustments to SCE's New Customer Only Calculation

SCE provided a NCO calculation in its marginal cost workpapers in recognition of several intervenors' preferences for using that methodology. This spreadsheet adds the average growth in each rate group, based on net customer counts from 2013 to 2015, to the number of customers requiring equipment replacement, based on a weighted average of the service life of each component of the TSM equipment. This sum is multiplied by the total present value of TSM equipment capital costs, and then the sum is divided by the number of customers in each rate group to arrive at SCE's NCO hookup cost for each group.

ORA appreciates SCE's effort to include a NCO calculation of customer access costs in its workpapers despite its support for the RECC method. However, ORA makes several adjustments to SCE's calculation method, principally to shift focus from net customer additions to the number of new

---

[9] SCE Application 65 CPUC 2d 362, 1996 Cal. PUC LEXIS 270, D.96-04-050, FOF 37 and 38.

connections required and to largely remove TSM equipment replacements from the calculation.

1. Customer Growth

ORA understands that the calculation of marginal customer costs under the NCO method is sensitive to the level of customer growth in each class. Indeed, one of SCE's major contentions with the NCO method is that relying on net customer growth or reduction numbers can "create unreasonable results," noting the possibility that for a shrinking customer rate group, "the utility still incurs new costs to install equipment" for newly added customers.[10] ORA hopes to address this issue with the following approach.

For each rate group, ORA took SCE's average growth projected over the next three years (2015-2017), and set a floor of zero for classes whose numbers are expected to decline. Next, ORA calculated the average recorded new meter installations for each class in the past three years, and then found the midpoint between the new meter installations and the adjusted customer growth rates.[11] This sequence of calculations is shown in Table 1-2 below.

---

[10] SCE-02, page 21 ll. 2-7.

[11] Customer populations and meter growth values were taken from SCE's response to Question 17 of ORA-SCE-GRC PHASE 2-LWT-003.

TABLE 1-2: ORA'S NCO GROWTH RATE

Rate Group	Average Net Growth	Growth Floor = 0	Average Meter Growth[12]	Ave. Net + Meter Growth
Domestic	1.1%	1.1%	0.5%	0.8%
GS-1	-0.3%	0.0%	1.4%	0.7%
TC-1	0.4%	0.4%	0.7%	0.6%
GS-2	1.5%	1.5%	0.6%	1.1%
GS-3	-0.1%	0.0%	0.7%	0.4%
TOU-8	-0.3%	0.0%	0.7%	0.4%
AG <= 200	-1.9%	0.0%	1.1%	0.5%
AG > 200	0.4%	0.4%	1.2%	0.8%
Street Lights	0.5%	0.5%	0.4%	0.5%

Shifting the focus to the number of new connections is consistent with PG&E's position in its most recent GRC Phase II filing:

> Even with net declining customers in a class due to disconnections, new connections do occur and the class needs to cover its cost of those new connections by recognizing new connections in isolation, rather than using new connections net of disconnections. For this 2014 GRC, PG&E proposes using new connection forecasts by customer class to calculate new connection rates instead of the proxy calculation using net changes in number of customers.[13]

There were several reasons that ORA adjusted SCE's growth levels in this manner. First, ORA is persuaded by PG&E's arguments that investment in new hookup equipment is really driven by the level of new connections in a given year. It is logical to conclude that each customer group causes SCE to incur growth-related costs even in years when more customer accounts are terminated than newly created. Furthermore, SCE's projected growth levels seemed to include the effects of customers switching rate schedules, which would not change the level of investment required to serve each class. ORA requested information on the number of transformers, service lines and meters installed each year in each

---

12 The data provided included levels of "legacy meter growth" along with "ESC [Edison Smart Connect] meter growth." Due to the very small number of legacy meters in most customer groups, but anomalously large numbers in the TOU-8 group, ORA used only ESC levels.

13 A.13-04-012, PG&E-5, page 7-11.

rate group, but was only provided this information for meters. In a follow-up request, SCE stated, "There are a number of scenarios (e.g. new construction projects) where a meter could be installed without being attached to an active customer account."[14] Thus, the number of meters installed each year is not a perfect proxy for the number of new connections required to serve new customers in each rate group. Also, ORA recognizes that ideally the number of new connections required would roughly track positive customer growth levels, though there may be timing differences between the two. Nevertheless, to deal with problems with each data set, ORA averages these meter installation levels with SCE's (adjusted) projected customer growth levels.

2. Hookup Replacement

ORA proposes that the cost driver for marginal customer access should be the number of new customers creating the need for TSM equipment to be installed. Thus, the full cost of replacements in each year should not be part of this calculation, since the commitment to replace customer access equipment was made at the time that equipment was installed. And, replacement costs are much more closely connected to the engineering service lives of the equipment and to environmental factors than to customer behavior. ORA accounts for the timing of these installations by including a replacement cost adder for new connections only, after SCE's projected replacement values are excluded.[15]

This treatment of replacement costs is consistent with SCE's and ORA's approach to calculating distribution demand marginal costs,[16] and is similar to that proposed by PG&E in its 2014 GRC II filing. PG&E excluded replacement costs altogether because "customer turnover and temporary vacancies have little bearing

---

[14] Response to ORA-SCE-GRC PHASE 2-LWT-Verbal 03.

[15] This is accomplished by dividing the initial investment costs by:

(1-(1+inflation rate)asset life/(1+discount rate)asset life)).

[16] For design demand, use of the RECC method implicitly includes replacement costs over the lifetime of the assets.

on equipment failure rates and no impact on equipment obsolescence requiring replacements.[17]

C. Customer Hookup Costs

SCE based the capital costs of customer hookups on engineering studies that cost out a series of "typical" hookups. Clearly, assumptions about what constitutes "typical," and whether the hypothetical typical configurations adequately represent the range of real world options, is difficult to verify. But ORA sent a data request asking whether SCE had validated its typical connection cost studies by comparing them with actual cost data. SCE responded by stating:

> No. The marginal cost developed is a unit estimate based on a theoretical set of assumptions that are consistently applied to the cost driver (labor and material) of the various methods of service.[18]

SCE, however, does contend that these studies accurately represent its actual costs. As explained in the same data request response, SCE analyzed 128 work orders upon ORA's request in 2012 that SCE provide sample hookup cost data, and concluded "that the theoretical approach used in the typical studies was representative of what was actually being recorded on the work orders."[19] A summary spreadsheet was provided along with this statement, but SCE did not provide information that substantiates its assertion.

As ORA noted in SCE's 2012 GRC Phase II, SCE should be directed to produce a comprehensive study of its costs to connect new customers to its distribution grid that might serve to justify its methodology. This in fact is the approach that PG&E uses. PG&E stated, in its 2014 GRC Phase II application, that its new connection costs were "computed based on [over 46,000] actual field-produced job cost estimates obtained from customer contracts in PG&E's CCBS application rather than a limited number of estimated 'typical customer

---

[17] A.13-04-012, PG&E-5, page 7-5.

[18] Response to Question 2 of ORA-SCE-GRC PHASE 2-LWT-003.

[19] *Ibid*. This research was not completed soon enough to be referenced in ORA's 2012 filing.

connection' costs" and that this "represents a vast improvement in the methodology and should be adopted."[20] ORA agrees with this approach.

In addition, ORA notes that the *only* change made from SCE's 2012 typical cost studies for the instant application was to scale up the TSM capital costs by an escalation factor. When asked to justify the assumption that these costs only change based on escalation over a three year period, SCE responded, "Handy-Whitman [the index used to derive the escalation factor] is recognized as the benchmark index for cost drivers pertinent to the utility construction industry for such costs."[21] ORA does not question the veracity of the Handy-Whitman Index, but notes that the relative costs of individual components in hookups are influenced by factors other than general inflation.

In 2012, ORA recommended a reduction in Residential hookup costs in recognition of the variation in this rate group's customer connections, some percentage of which require only an "infill" using an existing transformer. SCE responded to an ORA data request in this proceeding confirming that these connections do take place, but claimed these situations are "very uncommon."[22] Similarly, SCE's typical cost studies do not recognize any developer or customer contributions to hookup costs (under tariff Rules 15 and 16) that might reduce the costs paid by SCE, another factor included in PG&E's 2014 GRC II application,[23] and for which an adjustment was made in ORA's 2012 SCE testimony. ORA has refrained from making a similar adjustment herein since the typical hookup costs presented by SCE are lower than the line extension allowances. Nevertheless, within the range of what is regarded as "typical," it is possible that there may be outliers that exceed the cost of the line extension allowances. Though ORA has

---

[20] A.13-04-012, PG&E-5, page 7-6 ll. 11-17.

[21] Response to Question 10 of ORA-SCE-GRC PHASE 2-LWT-003.

[22] Response to Question 11 of ORA-SCE-GRC PHASE 2-LWT-003.

[23] A.13-04-012, PG&E-5, pp. 7-7 – 7-9. As noted, "Capturing this cost sharing ensures that customer new connection cost results only capture the marginal cost incurred by PG&E."

not made adjustments for infilling or line extension allowances, it raises these issues to highlight two potential sources of inaccuracy in SCE's cost studies.

D. Customer Services Marginal Costs

SCE states that, in addition to the costs required to connect customers to its distribution system and to measure their consumption, "SCE incurs marginal costs in managing its relationship with customers, including handling customer communications, measuring usage, maintaining records, and billing."[24] ORA has not made changes to SCE's customer services marginal costs but notes several deficiencies with SCE's calculations below.

1. Fixed vs. Marginal Customer Services Costs

Marginal customer costs should be based on costs that vary with changes in the number of customers. They should exclude costs that are fixed or embedded. However, in its response to an ORA data request, SCE claimed:

> Over the course of a single year, all of the costs in total are fixed and do not vary significantly for marginal changes in customer count. Additionally, all cost elements in the Summary tab are based on recorded data, and are therefore embedded.[25]

ORA questions the validity of including as marginal those items for which SCE does not realize measureable changes in costs as a result of the addition or subtraction of a customer. In PG&E's 2014 GRC II filing, PG&E proposed to remove fixed costs from its customer services costs, noting that "when there are significant fixed costs, as with billing or meter maintenance, use of an average cost proxy tends to overstate the true marginal cost by including fixed as well as variable costs in the calculation."[26] PG&E explains that the development of rate credits due to Electric Industry Restructuring allowed it to separate out its fixed

---

[24] SCE-02, page 15 ll. 20-22.

[25] Response to Question 13 of ORA-SCE-GRC PHASE 2-LWT-003.

[26] A.13-04-012, PG&E-5, page 7-16, ll. 7-9.

from its variable customer service costs.[27] Given time and resource issues, ORA was unable to identify comparable demarcations in SCE's customer services workpapers, but agrees in principle with PG&E.

2. Smartmeter Opt-Out Meter Reading

ORA sees two issues with SCE's inclusion of Smartmeter Opt-Out meter reading costs in residential marginal customer services. First, for every customer requiring meter reading under the program, SCE also collects ongoing revenues that are not accounted for in its cost studies. Second, although D.14-12-078 ruled that the residential class would be responsible for shortfalls representing the differences in costs and revenues associated with the program, including them in marginal customer costs results in those costs being scaled up by an EPMC multiplier along with the rest of SCE's distribution marginal costs.

ORA does not regard these costs as marginal for the vast majority of residential customers. Rather, they relate to a public benefits program the costs of which have been socialized, as are CARE or energy efficiency program costs, which generally are not included in marginal cost calculations. Thus, they should not be subject to EPMC scaling. Doing so would inflate the costs of the program that must be borne by all residential ratepayers.

ORA estimates that removing meter reading costs related to the Opt-Out Program would reduce SCE's meter reading marginal costs by about 28 percent.[28] However, this adjustment is not reflected in ORA's MCAC values because of the complications that arise from attempting to account for these costs elsewhere in the revenue allocation process while also adjusting for program revenues. Along with other customer services costs explained above, Edison should be directed in

---

[27] *Ibid*, ll. 23-28.

[28] Attachment to Question 13 of ORA-SCE-GRC PHASE 2-LWT-003; ORA calculated that meter reading for SCE's Opt-Out Program comprised $7.3 million of SCE's projected 2015 meter reading cost of $26 million.

future GRCs to present justification for Opt-out Program meter reading in its marginal cost calculations.

E. Residential Customer Charge Implications

The MCC values presented in this chapter represent ORA's proposal for the purposes of determining marginal cost responsibilities to be converted to revenue allocations for each customer class in this proceeding. ORA does not support using the marginal customer costs it provides for the purpose of determining fixed customer charges. If the Commission decides to do so, the deficiencies in SCE's estimates noted above would need to be addressed.

IV. CONCLUSION

Accurate marginal customer costs are a key input to electric rates because they have a major impact on the allocation of utilities' distribution revenue requirements among the various customer classes. The Commission should reject SCE's rental approach, as it did in five major marginal cost and rate design decisions in the 1990s, because the rental method overestimates the marginal cost of providing customer access to the distribution grid. The Commission should instead adopt ORA's proposed marginal costs, which are based on the NCO method it has adopted since 1992.

CHAPTER 2

MARGINAL DISTRIBUTION DEMAND COSTS

LOUIS IRWIN

TABLE OF CONTENTS

CHAPTER 2
MARGINAL DISTRIBUTION DEMAND COSTS
LOUIS IRWIN

I. INTRODUCTION

This chapter addresses Southern California Edison's ("SCE's") marginal distribution demand costs ("MDDC"). The MDDC values are an important input to the revenue allocation process. These costs are further subdivided into Distribution and Sub-Transmission costs. For the purpose of this proceeding, Sub-Transmission can be loosely defined as local transmission (feeding local substations) that is not under California Independent System Operator ("CAISO") jurisdiction. The Distribution system is defined as continuing from where Sub-Transmission ends and includes all local wires until the final line transformer.

The sole focus of this chapter, the Demand Costs, are the capital additions that lead to SCE being able to serve a larger load. Thus, capital additions serving repairs, safety, reliability and all other costs not attributable to increasing load are excluded. The MDDCs are expressed in the form of dollars per kW of added load.

The calculation of MDDC is not achieved through a simple ratio, but instead by a linear regression to resolve the relationship between dollars and kW of increased load.[1] The MDDCs are calculated using a ten year historical period (2002 through 2012) and five year "forecasted" period (defined as 2013 through 2017).[2] An important distinction to make is that, although the calculation of the MDDC includes a forecast period for data inputs, the goal is not to forecast an MDDC trend. The goal is to find two values, one each for Sub-Transmission and Distribution marginal costs, to be used for all years of the 2015 GRC.

---

[1] The two data series essential to this analysis are the investment costs and added capacity. The regression finds the trend line which minimizes the square of the distance between the trend and sample data

[2] An aspect of the lengthy GRC process is that by the time that it gets to Phase II, the "forecasted" period includes two past years, 2013 and 2014.

II. SUMMARY AND RECOMMENDATIONS

ORA limits its recommendations to the added load figures, both historical and forecasted – which include all 15 years of this series. As a result, ORA has made the following changes to SCE's calculations:

1. For the historical period (2003 to 2012), ORA uses the recorded annual peak loads, whereas SCE used its own planned loads.[3]
2. For the forecast period (2013 to 2017), ORA has calculated the compound growth rate derived from the historical years. ORA then applied this growth rate to the forecast period.

ORA makes these adjustments to the calculations of MDDC for both Distribution and Sub-Transmission. The following MDDC recommendations result from these changes.

TABLE 2-1: ORA AND SCE'S MDDC RECOMMENDATIONS.

	ORA	SCE
Distribution	\$99.90 / kW	\$89.29 / kW
Sub-Transmission	\$29.92 / kW	\$37.58 / kW

ORA's second change (to the forecast period data) was made primarily because SCE's planned loads are much higher than the actual load in the last year of the historical period (2012). Not making this change would have created an indefensible discontinuity when SCE's planned loads for the forecasted period are appended to the historical actual load series.

III. APPLICANT'S PROPOSALS

Traditionally, MDDC is calculated using the inputs of annual recorded peak loads and the investments made by the utility to support of the increase in those loads. The central controversy in this testimony, initiated by SCE, is to use the loads that it planned for in making those investments rather than the actual

[3] Recorded annual peak loads provided by SCE DR-07 Q. 2.

recorded peak loads for all ten of the historical years included in the analysis. SCE calls the loads it planned for "planned capacity." This is the planned capacity needed to accommodate increased peak loads. For simplicity in testimony, ORA will use the terms "planned load" versus "recorded load" when speaking of loads during the historical (2003 to 2012) period.

SCE first proposed the use of planned loads rather than recorded annual peak loads in the 2012 General Rate Case ("GRC"). In its current testimony, SCE may be trying to imply that this data issue is resolved when it stated that its proposal was "incorporated into the settlement [of the 2012 GRC]"[4] But since the matter was settled rather than litigated, the Commission was left with no precedent.[5]

SCE seeks to divorce itself from the recorded peak load data due to its variability. In doing so, however, SCE is omitting from the analysis how its investment plan responds to the excess distribution system capacity created when actual load growth is lower than expected. In fact, the planned investments for the five forecast years (2013 – 2017) are significantly lower than they were in the historical years most likely because load growth was much less than SCE had anticipated.[6]

Because planned load diverges widely from recorded load, SCE's proposal can have a large effect on MDDC and the ensuing Revenue Allocation and resulting rates. Figures 2-1 and 2-2 below illustrate the difference between planned and recorded annual peak loads. For convenience, they include the forecast years as well illustrating both SCE's and ORA's estimates of load in the forecast period.

[4] SCE-02, June 20, 2014, p. 12.lines 13-14.

[5] Ibid.

[6] For Non-ISO Transmission, the average forecasted investment (in 2012 $) was a little over two thirds of the average figure for the previous ten years. For Distribution, the same calculation had more dramatic results with forecast values being a bit less than one third the values for the historical years. See ORA Workpapers, Non-ISO Transmission Capital and Distribution Capital tabs.

FIGURE 2-1

Distribution Planned and Recorded Loads (MW)

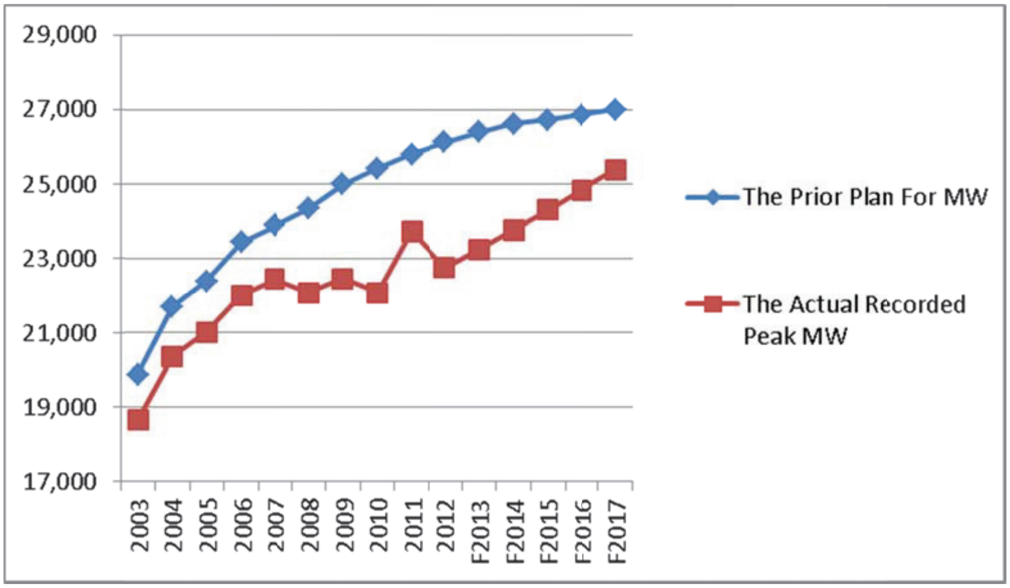
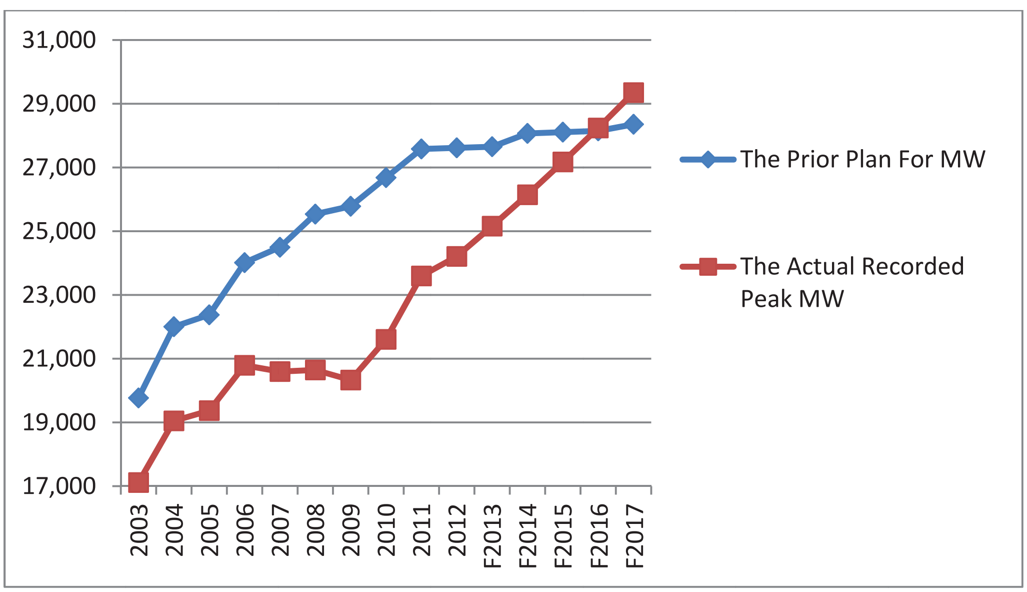


FIGURE 2-2

Sub-Transmission Planned and Recorded Loads (MW)



IV. DISCUSSION

A. Planned vs. Recorded Data for the Historical Period (2003 to 2012)

As previously stated, SCE proposes to use planned loads for the historical period (2003 through 2012), for both Distribution and Sub-Transmission. SCE's chief argument for using planned loads rather than recorded loads is that the planned loads smooth out the variations compared with the recorded data.[7] On the disturbances to recorded peak load data, SCE lists, "capacity that was lost during years of negative load growth such as during the recession beginning in 2008."[8] It goes on to justify its approach by saying that "Capacity expansion or negative growth due to recessions or dramatic conservation efforts as seen during the 2001 energy crisis, distort the average cost models by inflating the cost-to-growth ratio."[9] While SCE's justification emphasizes negative load growth, the recorded data also shows positive load growth during periods of economic rebound. These positives and negatives tend to balance out the cost-to-growth ratio that SCE mentions when a 10-year data series is used.

The regression model that SCE employs here was developed by a consulting firm, the National Economic Research Associates (" NERA").[10] And this model addresses the variability of both load and investment data by using 10 years of historical data. It uses the cumulative changes in the data, not the annual changes that are far more variable. Thus NERA approach for dealing with short-term fluctuations in the load data was to include enough historical data to capture both the natural increases and decreases in load. NERA does not make any recommendation, that ORA is aware of, to use planned rather than actual data to further smooth the historical trends.

---

[7] SCE-02, p. 12, lines 14-21.

[8] Ibid.

[9] SCE-2, p. 12, lines 18 -20.

[10] From the 2012 SCE GRC, Ex. SCE-02, p. 28, lines 13-15.

Note that when NERA developed its methodology several years ago, there were also swings in the economy, increases in energy rates and fluctuations in the weather and changes in a myriad of other influences on system load, such as the development of residential solar. One of the strengths of the NERA methodology is that it ties marginal costs to real data that can be easily validated, and not on a planner's estimates.

Another factor that concerns ORA about the use planned loads rather than recorded loads is that the planned loads have changed since the last GRC. Late in the discovery process, ORA compared SCE's planned loads for the 2015 GRC to the 2012 GRC. ORA was surprised to find that they did not match by a substantial amount for overlapping years (2003 to 2009). These differences in planned loads are shown below in Table 2-2.

Table 2-2 – PLANNED LOADS

	SUB-TRANSMISSION			DISTRIBUTION		
	2012 GRC	2015 GRC	Increase	2012 GRC	2015 GRC	Increase
2000	16,142	16,142	0	18,591	18,591	0
2001	16,392	16,392	0	18,609	18,609	0
2002	16,717	16,717	0	18,629	18,629	0
2003	17,114	19,766	2,653	18,648	19,873	1,225
2004	19,051	22,004	2,953	20,356	21,693	1,337
2005	19,372	22,374	3,003	20,999	22,378	1,379
2006	20,791	24,013	3,223	21,996	23,436	1,440
2007	21,206	24,493	3,287	22,438	23,873	1,435
2008	21,631	25,538	3,907	22,887	24,329	1,442
2009	22,063	25,782	3,719	23,344	24,981	1,637

As shown, planned loads have been increased in the 2015 GRC compared to the 2012 GRC. Focusing on the 2009 differences for Distribution and Sub-Transmission, the load increases are 1,637 MW and 3,719 MW respectively. Note that there are no differences for the years 2000 to 2002. These years are listed in the 2015 GRC but not used. Because of the late date, ORA has not obtained an explanation for this change. At first glance, ORA could not think of a legitimate reason for these planned loads to change for historical years. They presumably should be the loads that planners assumed when making investments into distribution capacity during the historical years. If those expected loads turned out to be wrong, one cannot simply change them after the fact because these loads allegedly reflect the expectations that underlie the historical investments, which in turn are a matter of historical record. Whatever happened, whether the changes are a form of revisionism or error correction, it amply demonstrates ORA's concern regarding the objective reality of SCE's "planned loads" when compared to recorded loads, and the difficulty of validating the planned loads.

B. Forecast Data for 2013 to 2017

Another problem with substituting a planning value into the historical years, which has a very different trend from the actual data, becomes evident when one compares the last year value in the historical planned series with the last year value in the historical recorded series. In 2012, the Distribution and Sub-Transmission IOU-planned load data have drifted substantially above the annual peak recorded load data. For both Sub-Transmission and Distribution, the planned load is about 3,400 MW (and 14+ %) higher than the recorded peak loads.[11] So by a substantial margin, the two trends are on different paths. Thus simply appending SCE's planned load for future years (2013 to 2017) to the recorded historical peak load data would have led to a sizable discontinuity in the series (a jump of 14+% from 2012). Thus ORA developed its own load forecast for the future years by simply applying the compound load growth during the historical period to the last year's recorded load.

ORA also did not use SCE's planned loads in the forecast period because the growth rate in that data is inexplicably low, indeed significantly less than that

[11] ORA results drawn from comparison of SCE-02 Workpapers, tabs Distribution Capital and Non-ISO Transmission Capital and SCE Response to DR-07 Q. 2, Summarized in ORA Workpapers, tab "Plan vs. Act.

of the planned loads in the historical period. For both Distribution and Sub-Transmission MDDC, the growth rate assumed in planning during 2003 to 2012 is 3.1%, while the future planned capacity growth rates are 0.5% and 0.7%, respectively.[12] So, in both cases, the growth rate for the future years is less than 25% of that in the historical years. The slow growth rate in the historical recorded peak loads may have led to a surplus of distribution plant relative to the need, suggesting that its future planned investment in distribution plant should be substantially less.[13] But that does not mean that the load itself should also be presumed to grow at a slower rate. Peak demand is driven primarily by economic and weather factors, not whether or not a utility made infrastructure investments.

The historical years do provide conservative growth rates that should be reasonable for forecasting future loads. Indeed, the historic growth rate of peak loads starts in 2003 on the heels of a major energy crisis and also includes 2008, probably the deepest recession since the "Great Depression" years, and as a result, should have some bias towards reducing the forecast growth rate from this data. Therefore, the risk of the forecast based on historic values being too high is less likely, even if the economic recovery in California should level off or stall. On this basis, ORA applies the historical actual growth rates to the future years. Again, SCE's planned load growth for the future years is more conservative by several fold than the recent past actual rates despite this recent past containing the recessionary years.

ORA's recommendations for the historical and future years leads to an increase in Distribution Demand MC from $89.29 to $99.90. But, for Sub-

---

[12] ORA Workpapers, Non-ISOTransmission Capital and Distribution Capital tabs. ORA calculated compound growth rates by using Excel's Goal Seek function set up to find the growth rate that resulted in each end value.

[13] For Non-ISO Transmission, the average forecasted investment (in 2012 $) was a little over two thirds of the average figure for the previous ten years. For Distribution, the same calculation had more dramatic results with forecast values being a bit less than one third the values for the historical years. ORA Workpapers, Non-ISO Transmission Capital and Distribution Capital tabs.

Transmission, ORA's recommendations lead to a decrease in MC from $37.58 to $29.92. The difference in outcomes for these two MCs is largely due to their difference in historical actual peak load growth rates. Since this rate is much higher for Sub-Transmission (3.9%), the future year values eventually overtake SCE's planned load values and reduce the marginal cost. For Distribution Demand MC, the growth rate is much lower (2.2%) and does not lead to forecasted peak load values exceeding SCE's planned future load values.[14] Therefore, ORA's MC value is lower than SCE's in this case. This difference in outcome is also reflected in Figures 2-1 and 2-2 where the lines cross for planned and actual loads in the forecast period for Sub-Transmission, but do not for Distribution.

V. CONCLUSION

ORA has demonstrated the divergence of the planned load data from recorded peak load and shown how this creates issues for the forecast period. The forecasted planned load did not reasonably match the end year of the historical loads. The excess in planned loads and SCE's subsequent slowdown in capacity investment was not at all matched to the traditional drivers of load growth (such as the economy).

SCE did not demonstrate sufficient cause to deviate from the method prescribed by NERA. On the contrary, it showed the difficulties generated by using planned loads instead of recorded peak load data. Proper rate design is dependent on the MDDC values being estimated accurately. ORA recommends that the Commission adopt ORA recommendations for MDDC which results in values of $99.90 for Distribution MDDC and $29.92 for Sub-Transmission MDDC.

[14] ORA results drawn from comparison of SCE-02 Workpapers, tabs Distribution Capital and Non-ISO Transmission Capital and SCE Response to DR-07 Q. 2, Summarized in ORA Workpapers, tab "Plan vs. Act.

CHAPTER 3

MARGINAL ENERGY COSTS

ROBERT FAGAN

AND

PATRICK LUCKOW

TABLE OF CONTENTS

I. INTRODUCTION AND SUMMARY OF FINDINGS

What is the purpose of this testimony?

The purpose of this testimony is to examine Southern California Edison's ("SCE's") proposals for marginal energy and capacity costs in Phase 2 of its 2015 General Rate Case ("GRC" 2).[1] We focus on the production cost modeling of marginal energy costs (using PLEXOS[2]), and SCE's loss-of-load-expectation ("LOLE") modeling as applied to projected marginal capacity costs.

What is the structure of your testimony?

We review the monthly and time-of-day patterns of wholesale marginal energy costs, and the inputs to SCE's PLEXOS modeling that underlie those costs for the 2015-2017 timeframe. We examine SCE's LOLE modeling results on an hourly and monthly basis, and how those results affect estimates of marginal capacity costs on a TOU costing period basis. We observe how energy and capacity costs change for different hours of the day, and for different months.

We use the most recent load forecast data from the California Energy Commission[3] ("CEC") and re-run SCE's base PLEXOS production cost simulation to provide a comparison set of marginal energy prices. We re-run SCE's loss-of-load-expectation ("LOLE") model with the same updated load information. We also show how marginal energy costs change under different natural gas price assumptions, running a PLEXOS sensitivity with different natural gas prices; and we conduct a PLEXOS sensitivity that uses a higher level of solar PV resources in 2016 and 2017 than is used in SCE's modeling. We also re-run the LOLE model for our solar PV sensitivity.

Lastly, we discuss our findings and provide recommendations to the Commission on SCE's proposal for marginal energy and allocation of capacity costs on TOU periods.

---

[1] As described in SCE's June 20, 2014 filing, "Phase 2 of 2015 General Rate Case Marginal Cost and Sales Forecast Proposals".

[2] PLEXOS is Energy Exemplar's production cost simulation modeling tool. Synapse licenses PLEXOS from Energy Exemplar and performs production cost modeling simulations.

[3] CEC Staff Final Report, California Energy Demand (CED) Updated Forecast, 2015-2025, CEC-200-2014-009-SF, December 2014.

Please summarize your findings.

Our review of SCE's proposal for marginal costs for energy and capacity did not find any major concerns with SCE's methodologies for assessing hourly marginal costs. We did find expected minor difference in modeling results when we updated the load forecast inputs; and differences when we tested sensitivities reflecting higher and lower gas prices, and a higher level of solar PV production in 2016 and 2017.

Synapse's re-run of the PLEXOS model using an updated load forecast (the CEC updated CED forecast, January 2015) found very minor changes to the wholesale energy costs for 2015-2017, compared to SCE's results. Synapse's gas price sensitivity results did change the marginal energy costs significantly, as expected, but did not change the relative patterns of hourly marginal cost differences. Synapse's re-run of the LOLE model using the updated load forecast showed some variation on relative risk of loss of load from that of SCE's. Synapse's sensitivity run of PLEXOS using a higher level of PV resources in 2016 and 2017 found minimal change to marginal energy costs.

II. SUMMARY OF SCE'S MARGINAL COST ESTIMATION METHODOLOGY FOR ENERGY AND CAPACITY

Please summarize how SCE determines marginal costs for energy.

SCE derives its marginal energy costs from a combination of wholesale (incremental) energy costs and the premium associated with incremental requirements for Renewable Portfolio Standard ("RPS") eligible resources.[4] SCE uses two sources of energy price information to determine hourly-based wholesale energy costs: bilateral forward prices from a broker[5] and projected prices based on PLEXOS production cost modeling. For 2015, and the first portion of 2016, SCE uses solely its bilateral forward market prices to determine hourly marginal energy costs. For the rest of 2016 and all of 2017, SCE uses the bilateral forward market costs in a "blended" combination with the results of its PLEXOS production cost modeling, which

---

[4] As described in SCE's June 20, 2014 filing, "Phase 2 of 2015 General Rate Case Marginal Cost and Sales Forecast Proposals" Page 28-30.

[5] See SCE Data Request Response ORA-SCE-GRC PHASE 2-LWT-005 Follow-up, provided to ORA on January 8th, 2015.

produces hourly market clearing prices for the south of Path 15 (SP15) region of California.[6] We do not have any immediate concerns with this methodology, and in fact the broker forwards appear quite close to the PLEXOS model outputs.[7]

SCE adds an RPS premium to the forecast of wholesale market energy marginal costs to create its final generation energy marginal cost. To calculate this RPS premium, SCE uses its own forecast for annual RPS contract payments blended with an average of Western Electricity Coordinating Council ("WECC")-wide premiums associated with utility green pricing programs from May 2013, as catalogued by the Department of Energy ("DOE"). The average SCE calculated premium is 5.36 c/kWh and the WECC-wide premium is 1.69 c/KWh. The SCE value is weighted at 68%.

How does SCE map these energy costs across time periods?

SCE averages those blended hourly costs according to its five defined time-of-use ("TOU") costing periods. Table D-1 (page D-1) of SCE's proposal contains SCE's TOU-8 periods. Those periods include:

- Three summer periods (four months, June through September): on-peak (noon to 6 PM, non-holiday weekdays), mid-peak (8 to noon, and 6 pm to 11 pm, non-holiday weekdays), and off-peak (all other summer hours).
- Two winter periods (eight months, January through May, October through December): mid-peak (8 AM to 9 pm, non-holiday weekdays) and off-peak (all other winter hours).

SCE's proposed TOU periods are the same as is currently reflected in their TOU-8 periods. Those periods are based on SCE's "periodically perform[ing] a costing period study"[8] to determine if they should be changed. By averaging the blended hourly costs over the relevant TOU period, SCE determines a set of marginal energy costs that can be applied to consumption occurring during any given TOU costing period.

---

[6] PLEXOS zonal configuration includes all SCE load in a "SCE" region which is south of the physical Path 15, a transmission path roughly separating northern and southern California.

[7] We do note, however, that our sensitivity modeling will show no changes to the generation energy marginal cost value in 2015, and little in 2016, as a result of this blending methodology.

[8] SCE at page D-1.

Please summarize how SCE determines marginal costs for capacity.

SCE estimates marginal capacity costs based on the cost of a new combustion turbine[9], reduced to account for the "energy rent"[10] associated with its operation. We do not analyze SCE's computation of marginal capacity costs; ORA witness Mr. Yakov Lasko addresses this in his testimony.

Please summarize how SCE assigns those marginal capacity costs across time periods.

SCE assigns those costs across the same five time-of-use costing periods as noted above for marginal energy costs. SCE states that it assigns these costs to the TOU costing periods based on the results of its LOLE model[11], which determines the relative LOLE for each hour of the year. SCE sums up the relative share of LOLE across the hours within the defined TOU periods to produce marginal cost allocators for capacity, seen in SCE's Table I-7.

How does the LOLE Model Work?

The LOLE model uses probabilistic inputs for forecast loads, resource forced outages, and wind and solar output, and determines whether or not there is a shortage of resources (i.e., load and supply are not able to be balanced), and the quantity of that shortage (in MWh) for each hour of 2017.[12] These shortage values are then normalized[13] to produce a "relative LOLE" for each hour of the year.

III. ANALYSIS OF SCE "BASE" CASE

What are SCE's proposed marginal energy costs?

SCE proposed marginal energy costs are based on wholesale energy prices, and on the RPS "premium", weighted by SCE to reflect a 24.8% sourcing requirement for RPS energy[14]. Table 1 lists SCE's marginal energy costs, by SCE's proposed TOU costing period.

---

[9] SCE page 22-25.

[10] Energy rent is the revenue earned above cost of operation for energy provided by the combustion turbine. The remaining costs are the effective "residual" marginal capacity costs. SCE at 22-23.

[11] SCE, 2:12 to 26:1

[12] This is SCE's "spreadsheet-based resource balance model", SCE at page 26.

[13] SCE at 27.

[14] SCE at Table I-8.

Table 1. SCE Proposed Marginal Energy Costs (MEC) by TOU Costing Period

Cents/kWh ($2015)		Summer (June – September)			Winter (Jan-May, Oct-Dec)	
	Ann	On-Pk	Mid-Pk	Off-Pk	Mid-Pk	Off-Pk
Wholesale Market Energy	4.29	5.78	4.70	3.68	4.83	3.94
RPS Eligible Energy	4.18	4.18	4.18	4.19	4.19	4.18
Weight for RPS	.248	.248	.248	.248	.248	.248
RPS Weighted	1.04	1.04	1.04	1.04	1.04	1.04
Total Generation	5.33	6.82	5.73	4.72	5.87	4.98

Source: SCE Table I-8, and response to ORA Q01 Attachment 1.

What are SCE's proposed marginal capacity costs?

SCE's proposed capacity costs are listed in Table 2, by TOU costing period. SCE derives proposed capacity costs based on the backstop cost of a combustion turbine, and then allocates these costs across TOU costing periods based on the relative probability that marginal capacity will be required during that costing period. As seen, almost all marginal capacity cost is allocated to summer costing periods.

Table 2. SCE Proposed Marginal Capacity Costs (MCC) by TOU Costing Period

		Summer (June – September)			Winter (Jan-May, Oct-Dec)	
	Ann	On-Pk	Mid-Pk	Off-Pk	Mid-Pk	Off-Pk
Annual Capacity Cost, $/kw-yr	120.39					
LOLE Relative Share	1.00	0.8355	0.1264	0.0382	0.0004	0.0000
TOU Period Capacity Cost, $/kw-yr	120.39	100.52	15.22	4.60	0.05	0.00

Source: SCE Tables I-6, I-7.

Please summarize SCE's LOLE model and the inputs.

SCE developed a spreadsheet-based loss-of-load-expectation (LOLE) model to determine relative hourly LOLE, and uses the results of that model to assign marginal capacity costs to usage that occurs during periods with relative LOLE greater than zero. The model calculates "a probabilistic estimate of the fraction of time the SCE system is unable to meet demand"[15]. The LOLE metric – available for every hour, for the year 2017 – can be used to allocate marginal capacity costs to collections of hours when the LOLE is greater than zero. SCE provides the

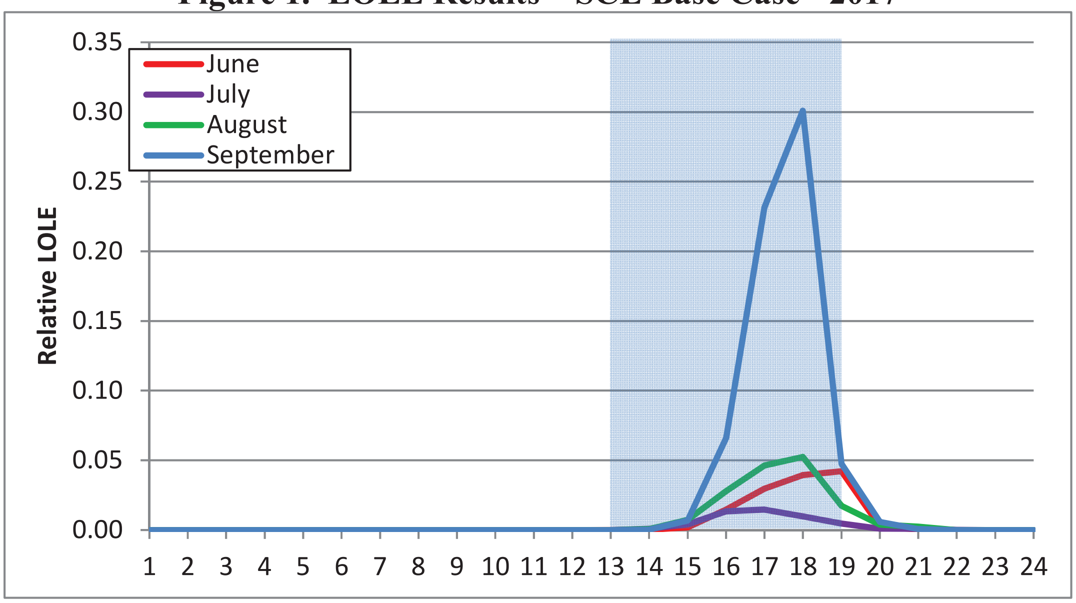
[15] SCE, page 26.

relative LOLE for each of its five TOU costing periods by summing up the hourly occurrences of LOLE within each costing period bin.

What are the hourly results of SCE's LOLE analysis?

SCE presents a summary of its LOLE analysis in its proposal, at Table I-7, presenting the summary "Relative LOLE Factors" that show LOLE across the five TOU costing periods. We show those values in Table 2. Figure 1 below shows a finer disaggregation of the LOLE values, for 2017. It illustrates the distribution of LOLE in the summer months (LOLE is effectively zero in the winter months, see Table 2), and it shows how that LOLE is distributed across months, and hours.

Figure 1. LOLE Results – SCE Base Case - 2017



Source: Synapse, based on SCE's LOLE model results as presented in response to discovery, ORA-SCE-GRC PHASE 2-LWT-001.

Please comment on SCE model inputs for the wholesale energy component of the marginal energy cost estimation.

Critical model inputs for wholesale price forecasting include the load forecast, the array of resources used to meet load, and the fuel prices – especially natural gas – used in the PLEXOS production cost simulation. SCE major assumptions start with the 2010 LTPP database, and includes updates by SCE such as information on non-SCE California entity loads, available in the 2012 CEC IEPR; and natural gas price forecasts from February 2014.[16]

---

[16] SCE-1 at Appendix C, pages C-1 to C-2.

SCE uses its own load forecast from March of 2013 for annual peak load and energy requirements.[17] As discussed in the next section, Synapse has re-run the PLEXOS model using updated peak load and annual energy forecast information from the CEC's update to the 2013 IEPR load forecast. The marginal energy costs – represented by the clearing prices that result from the PLEXOS modeling run –vary minimally from SCE's analysis using their March 2013 load forecast, compared to the most recent CEC updated forecast values. We note that SCE does not provide information that would allow us to reconcile their March 2013 load forecast with the updated information available from the December 2014 CEC CED updated load forecast.[18]

The set of California and WECC-wide resources contained in the PLEXOS dataset (from the 2010 LTPP PLEXOS database) reflect actual supply side conditions projected to be in place over the 2015-2017 time period. SCE used a natural gas forecast from February of 2014. As noted in the notes to Table I-8, SCE's marginal energy costs are based on an average gas price forecast of $4.64/mmBTU. SCE's transmission assumptions in PLEXOS reflect major transmission path capacity around the WECC, as present in the 2010 PLEXOS database.

In our estimation, SCE's inputs are reasonable to determine relative marginal energy costs across the TOU costing periods.

Please comment on SCE's use of the LOLE model to determine aggregate "Relative LOLE Factors"[19].

SCE uses the results of their hourly LOLE model to determine the relative LOLE factors seen in their Table I-7. SCE's use of the LOLE model as a means to determine hourly periods when loss of load is at risk is reasonable, and the inputs to the LOLE model are reasonable.

IV. ORA MODELING

What modeling analysis did Synapse conduct as part of its review of SCE's marginal energy and marginal capacity costs?

We re-ran the PLEXOS production cost simulation for the years 2015 to 2017, and we re-ran SCE's hourly LOLE model (2017 only[20]) to reflect updates to the annual energy (GWh) and

---

[17] SCE-1 at Appendix C, page C-2.

[18] SCE response to discovery, ORA-SCE-GRC PHASE 2-LWT-001 Follow-up.

[19] As reported in Table I-7.

peak MW load forecast, and an attendant change to the RPS resources required to meet the lower forecast load (i.e., a reduced level of RPS resources was needed in the re-run in order to meet the target percentage of RPS resources). We refer to these runs as ORA base runs or base scenarios.

We also re-ran the PLEXOS modeling - and in a more limited way, the LOLE model - for a few different sensitivity cases to gauge the way in which marginal energy costs change, and to assess if the pattern of hourly LOLE changes appreciably. Those sensitivity cases included a high and low gas price run (using SCE's original loads), and a high PV case, using PLEXOS; and a sensitivity run of the LOLE model with increased solar PV. The PLEXOS sensitivity runs were conducted for 2015 through 2017; the LOLE sensitivity was run for 2017 only.

Why did you run these alternative scenarios?

We reran the PLEXOS modeling with updated load forecast information because the information was available, and we wanted to see whether the changed load forecast would have any significant differences on either the energy prices, energy price patterns, or the LOLE hourly distribution. We did sensitivity analyses to assess the robustness of the marginal energy costs and the LOLE distributions.

Please describe the nature of the changes you made to the load inputs to reflect the updated CEC CED load forecast, for the ORA base case runs.

The CEC load forecast contains annual energy and peak demand by load zone in California, as reflected in the forms that contain the load forecast data. The 2015-2025 update (December 2014) contained lower levels of both annual energy, and MW peak demand, for the SCE-TAC region compared to the 2013 IEPR CED forecast, and compared to the values used in SCE's PLEXOS run. Table 3 compares the key load forecast values.

---

[20] SCE's LOLE model is constructed only for 2017. Synapse did not extend the model to explicitly consider results with updated load input and RPS quantity assumptions for 2015 and 2016.

Table 3. Annual Energy and Peak Demand Forecasts, SCE TAC Area, 2015-2017

	2015	2016	2017	Comment / Source
Annual Energy, GWh, SCE TAC Area				
SCE Energy	109,390	110,307	110,961	SCE PLEXOS
IEPR Energy	106,136	106,013	106,041	2013 IEPR Form 1.5a April 2014 / Mid demand, mid AAEE
Updated IEPR Energy	104,991	104,661	104,614	Updated Form 1.5a January 2015 / Mid demand, mid AAEE
Peak Demand, MW, SCE TAC Area				
SCE Peak	23,868	24,141	24,348	SCE PLEXOS
IEPR Peak	23,768	23,812	23,873	Form 1.5b April 2014 / Mid demand, mid AAEE
Updated IEPR Peak	23,533	23,514	23,560	Updated Form 1.5b January 2015 / Mid demand, mid AAEE

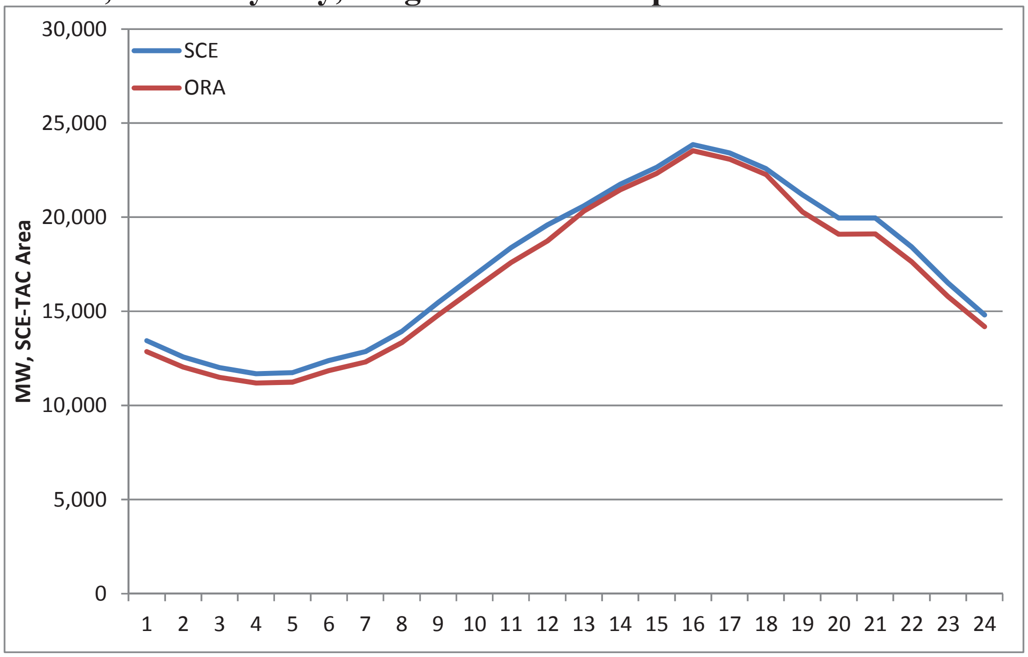
Source: SCE, California Energy Commission LSE and Balancing Authority Forecasts

For 2017, for example, the peak demand forecast was 3.2% lower in the updated IEPR forecast than the forecast peak in SCE's Plexos data, and the annual energy was 5.7% lower than the annual energy in SCE's PLEXOS data (the changes were lower than these adjustments for year 2015 and 2016). We needed to adjust the overall 8,760 hour load profile in PLEXOS in each year to account for the updated forecast. We first adjusted summer peak period hours to achieve the lower peak period value; and then we adjusted all other hours of the year to reach the overall energy target.

We adjusted both the annual energy and peak MW load forecast to align with values for the SCE-TAC area in the CEC updated CED 2015-2025 forecast[21], and also the level of RPS resources available to reflect the different load forecast. Figures 2 and 3 below illustrate the effect of our adjustment to load on a peak day in July.

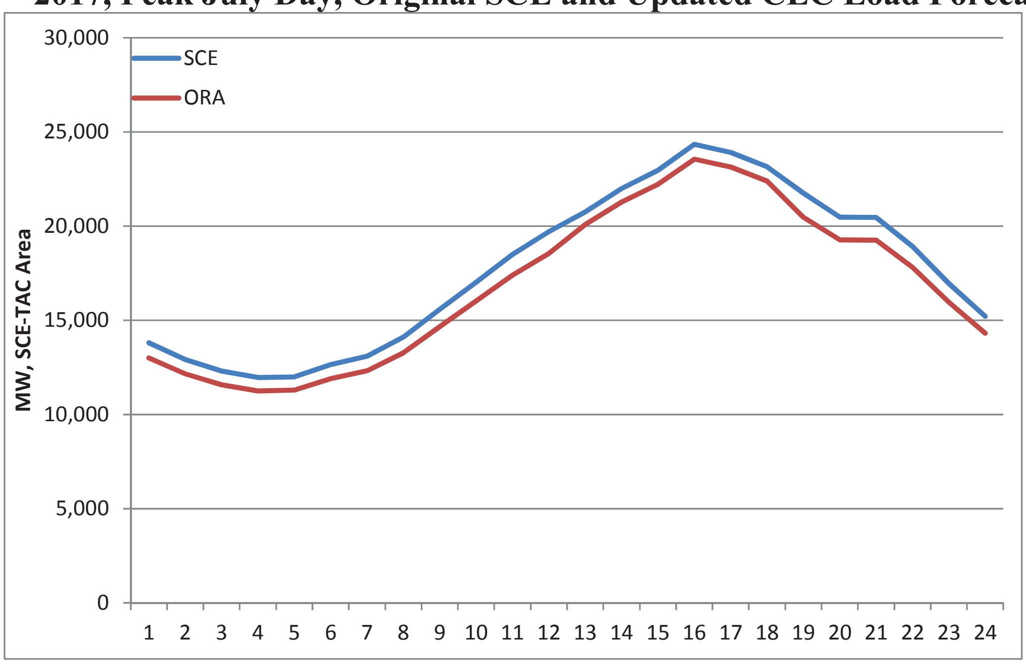
[21] SCE-TAC area, CEC updated forecast cite.

Figure 2 – 2015, Peak July Day, Original SCE and Updated CEC Load Forecast



Source: Synapse update of SCE PLEXOS load profile, peak July day.

Figure 3 – 2017, Peak July Day, Original SCE and Updated CEC Load Forecast



Source: Synapse update of SCE PLEXOS load profile, peak July day.

What were the results of your modeling?

Table 4 below summarizes the results of our re-running the Plexos model for our “base” case. It shows the raw PLEXOS price results (aggregated by TOU period, for each year) in comparison to SCE’s results.

Table 4. ORA/Synapse “Base” Model Results – PLEXOS Wholesale Energy Prices

	Wholesale Market Price - PLEXOS (nominal $/MWh)						Percent Difference, ORA Prices vs. SCE Original Prices		
	2015		2016		2017				
TOU Period	ORA	SCE	ORA	SCE	ORA	SCE	2015	2016	2017
Summer On	52.9	53.0	52.4	52.7	53.3	54.1	-0.3%	-0.6%	-1.5%
Summer Mid	45.8	46.3	45.4	46.3	47.1	48.2	-1.1%	-1.9%	-2.3%
Summer Off	39.3	39.8	39.4	39.8	41.0	41.7	-1.1%	-1.1%	-1.5%
Winter Mid	47.6	48.7	45.9	46.8	46.9	48.1	-2.2%	-1.9%	-2.4%
Winter Off	39.2	40.2	38.9	39.8	40.4	41.2	-2.6%	-2.2%	-2.0%
Summer	43.5	43.9	43.3	43.8	44.8	45.5	-0.9%	-1.2%	-1.7%
Winter	42.3	43.4	41.5	42.4	42.8	43.8	-2.4%	-2.1%	-2.2%

Source: Synapse PLEXOS run w/ updated load and RPS inputs.

Table 5 shows our results in comparison to SCE’s results when including the effect of the RPS premium, for “Blended Generation Energy Marginal Costs”. We did not change the RPS price component for this blended generation energy marginal cost metric.

Table 5. Blended Generation Energy Marginal Costs (2015$, averaged 2015-2017)

	SCE	ORA	% Difference
Annual	5.33	5.31	-0.3%
Summer On	6.82	6.81	-0.1%
Summer Mid	5.73	5.72	-0.3%
Summer Off	4.72	4.70	-0.2%
Winter Mid	5.87	5.85	-0.4%
Winter Off	4.98	4.96	-0.4%

Note: SCE values from Table I-8. ORA values are from re-run of PLEXOS, and addition of RPS premium. No change was made to the RPS premium component to develop the blended costs for the ORA results.

Table 6 shows the relative LOLE results of our re-run of SCE’s LOLE model, using updated load forecast inputs and RPS quantities.

Table 6. ORA/Synapse Relative LOLE

		Summer (June – September)			Winter (Jan-May, Oct-Dec)	
	Ann	On-Pk	Mid-Pk	Off-Pk	Mid-Pk	Off-Pk
SCE LOLE Share	1.00	0.8355	0.1264	0.0382	0.00004	0
ORA/Synapse Re-Run, LOLE Share	1.00	0.9376	0.0431	0.0192	0.00009	0

Source: Synapse Re-run of LOLE model w/ updated load and RPS inputs; and SCE Table I-8, and response to ORA Q01 Attachment 1.

Please explain what Tables 4 through 6 illustrate.

Table 4 shows that in Synapse's re-run of PLEXOS with updated load inputs, the wholesale market energy prices changed only minimally, especially for the on-peak periods. Table 5 shows that when considering the "blended" combination of wholesale price and RPS premium adder, the percentage change is barely discernible for summer on-peak periods, and a bit higher but still less than one-half of one percent for the other TOU costing periods. Table 6 does show changes between LOLE occurrences in the on-peak period vs. the mid-peak period, compared to SCE's modeling. This is an artifact of the change in load profile required to reconcile the updated load forecast.

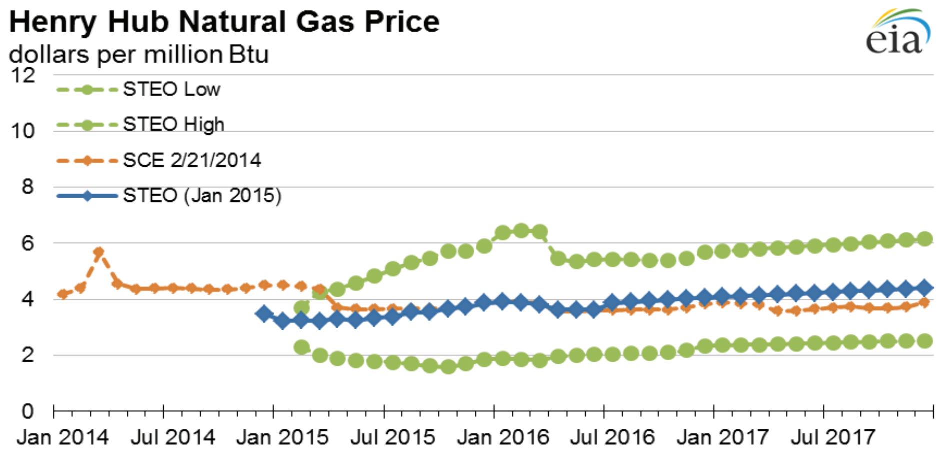
The patterns of hourly prices during summer and winter months seen in ORA's re-run of PLEXOS are similar to those seen in SCE's results.

Please explain additional "sensitivity" runs Synapse conducted when examining marginal energy costs and relative LOLE.

We re-ran the PLEXOS model to test the sensitivity of the results to changes in gas price, and changes in the level of solar PV renewables available for the year 2017. Figure 4 below shows the "high" and "low" gas prices used, along with prices used by SCE in their PLEXOS runs, and the Energy Information Agency ("EIA") short-term energy outlook ("STEO") prices from January 2015.[22]

[22] The STEO only extends to December 2016. For subsequent months, we let the price grow at the average 2015-2016 growth rate.

Figure 4 Gas Prices Used in Sensitivity Analyses



Source: Synapse, using US EIA Short-Term Energy Outlook data, and SCE data.

What are the results of the sensitivity runs for blended generation marginal energy costs?

Table 7 below shows the results of our sensitivity runs.

Table 7. Synapse Sensitivity Model Results – Blended Generation Marginal Energy Costs

		ORA Sensitivities			Delta % from SCE		
$2015, average $/MWh (2015-2017)	SCE	Low Gas	High Gas	Inc. PV	Low Gas	High Gas	Inc. PV
Annual	5.33	4.90	5.57	5.33	-8.0%	4.6%	0.0%
Summer On	6.82	4.90	6.98	6.81	-28.1%	2.5%	-0.1%
Summer Mid	5.73	5.05	5.89	5.74	-12.0%	2.8%	0.2%
Summer Off	4.72	4.11	4.84	4.73	-12.8%	2.6%	0.2%
Winter Mid	5.87	5.50	6.22	5.87	-6.3%	5.9%	0.0%
Winter Off	4.98	4.69	5.24	4.98	-5.7%	5.3%	0.0%

Source: SCE values from SCE Table I-8. Synapse PLEXOS sensitivity runs for the other cases.

What does Table 7 indicate?

Table 7 shows how the blended generation marginal costs vary for three different sensitivity runs. As expected, higher natural gas prices produce higher spot energy prices, and lower gas prices produce lower prices, since gas-fired units are on the margin in California. Incremental amounts of solar PV in 2016 and 2017 (i.e., 500 MW of incremental installed capacity) have a minimal effect on the overall average 2015-2017 blended marginal energy costs.

Did you re-run the LOLE model for 2017 with a solar PV sensitivity?

Yes. Table 8 below shows the results of re-running the LOLE model, for 2017, using 500 MW of additional solar PV on SCE's system, compared to SCE's base solar PV levels, and for comparison it also shows the re-run of the model with just the load update (as seen in Table 6). Additional solar PV has the effect of reducing the incidence of LOLE during the noon-6 PM summer on –peak hours, and increasing the LOLE during the summer mid-peak hours. This is seen in Table 8. These results are logical; more solar PV increases the need for resources to be available in the times just before, at and after sunset in the summer, and thus the LOLE model reflects higher expectation of LOLE in the hours after 6 PM (the mid-peak) when such solar PV resources are no longer available.

Table 8. Synapse Sensitivity Model Results, LOLE Model 2017

	Summer			Winter		
	On-Peak	Mid-Peak	Off-Peak	Mid-Peak	Off-Peak	Annual
SCE	0.8355	0.1264	0.0382	0.00004	0	1
ORA PV	0.8149	0.1462	0.0384	0.00045	0	1
ORA IEPR	0.9376	0.0431	0.0192	0.00009	0	1

Source: SCE; and Synapse LOLE model re-runs.

V. DISCUSSION / RECOMMENDATIONS

Please discuss the key points associated with your review of SCE's proposed marginal energy costs, marginal capacity costs, and loss-of-load expectation modeling. Please note your observations on TOU costing periods.

Synapse analyzed the inputs to, and the results of, two key models used by SCE: the PLEXOS production cost simulation model, used to gauge marginal energy costs; and SCE's use of a spreadsheet model to estimate hourly-based loss-of-load expectation, which will be used to proportionately assign marginal capacity costs to defined TOU costing periods.

The methodologies used by SCE to gauge marginal energy, and marginal capacity cost allocation are sound. These include the use of the PLEXOS production simulation model, and the use of a resource-balancing spreadsheet model to assess relative loss-of-load expectation. While we observed higher forecast loads in SCE's analysis compared to the most recent data available from the CEC, the blended marginal energy generation costs were not significantly different in our analysis using these updated data, when compared to SCE's original analysis.

Our sensitivity analyses did not reveal any unexpected outcomes, and while they are informative to understand how marginal costs may change with different assumptions, they do not lead us to question any of the core methodologies or results obtained by SCE.

Do you have any recommendations?

Yes. We note the values from our re-run of PLEXOS are minimally different from SCE’s proposed marginal energy costs. We recommend that the Commission approve SCE’s proposed marginal energy costs, based on our review noted in this testimony.

CHAPTER 4

MARGINAL GENERATION CAPACITY COSTS

YAKOV LASKO

TABLE OF CONTENTS

CHAPTER IV
MARGINAL GENERATION CAPACITY COSTS
YAKOV LASKO

I. INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

ORA has performed a comprehensive analysis of SCE's marginal generation capacity costs and has found the values provided by SCE are overstated.

SCE presents separate marginal cost components for generation capacity and energy, as has been the practice during most of the Commission's thirty-year history of basing electric rates on marginal costs. ORA's marginal energy costs, calculated by Synapse Energy Economics, are presented in Chapter III of ORA's testimony, and marginal capacity costs are discussed in this chapter. ORA recommends an annual marginal generation capacity cost of $83.71/kW-year,[1] including a 15% resource adequacy adder. This value is about 40% less than that proposed by SCE, and is based on the following adjustments to SCE's value:

1. A modification of SCE's proposed Real Economic Carrying Charge (RECC) method to reflect lack of need for new generating capacity before January 1, 2021,
2. Deduction of ancillary services rents, and
3. Adjustment of the discount rate to 7.9% instead of 10% as proposed by SCE.

[1] SCE's proposed MGCC, $122.85/kW-year excludes the 15% resource adequacy adder in their testimony. However, SCE's workpapers on Marginal Cost Revenue Responsibility do incorporate the 15% RA adder for a total value of $141.29/ kW-year. On a comparable basis (excluding the adder), ORA proposes $72.79/kW-year.

II. POLICY BACKGROUND

As described by SCE:

> The Commission has a long-standing policy of developing marginal generation costs using the deferral value of a CT [combustion turbine] proxy for estimating the avoided cost of capacity, and a system marginal energy cost for estimating the avoided cost of energy. This is an appropriate approach in California's current hybrid market, where energy procurement is transacted largely through market transactions, and capacity requirements are met through a combination of utility long-term procurement and annual resource adequacy requirements.
>
> The marginal cost analysis presented here is intended to represent conditions expected to occur during 2015 through 2017.[2]

ORA agrees with this general characterization of the Commission's policy and, in particular, with SCE's proposal to separate the energy and capacity marginal cost components. While SCE is correct in stating that the Commission has used the deferral value of a combustion turbine ("CT") proxy for estimating the avoided cost of capacity,[3] SCE neglects to state that the Commission has a long history of adjusting the CT deferral value downward, reflecting a reduced marginal generation capacity cost (MGCC) when surplus capacity exists.

For nearly a decade, the Commission used an Energy Reliability Index (ERI) to adjust the annualized CT cost downward when it found the existence of near-term surplus capacity. The ERI methodology fell out of use with electric industry restructuring in the late 1990s, and is now considered obsolete. As mentioned in the SCE testimony, quoted above, after a hiatus, the Commission reinstated separate marginal cost components for capacity and energy. Since 2001, the capacity costs always have resulted from various settlements. While some parties proposed to use the full annualized cost of capacity, other parties

---

[2] Ex. SCE-02, pg. 21.

[3] Equivalently, the CT cost, annualized in real dollars.

proposed lower values, and the settled values have generally been somewhat below the full annualized capacity cost.

ORA finds that SCE's proposed MGCC values are overestimated because SCE does not adjust MGCC downward to reflect near-term surplus capacity. As described by SCE, its RECC methodology is equivalent to a deferral approach in which "the present worth of the annual revenue requirements for an asset and its subsequent replacements are computed [based on 2015 installation], and then compared to the present worth of an equivalent asset and its replacements installed one year later [in 2016].[4] ORA proposes to modify SCE's RECC approach by computing the deferral value of a 2020 CT installation deferred to 2021. This adjustment, reflecting the time value of money, reduces the MGCC by about 25%. As discussed below, no new generation capacity is needed in SCE's territory through at least 2020. Both Commission precedent and mainstream economic theory dictate that the marginal capacity cost used to set retail prices should be reduced, relative to its long-run value, when near-term surplus capacity exists.

This adjustment is applied after the starting CT proxy value is adjusted for energy rents. There also is a long history of adjusting the proxy CT value for energy rents, and this adjustment is done by all three large utilities. SCE describes energy rents as "the operating profits that a proxy CT is able to earn when market prices are above the CT's variable operating costs, which principally consist of fuel, emission costs, and variable O&M."[5] SCE proposes to "deduct its estimate of energy rent, resulting in about a 5% reduction to its "full CT proxy cost."[6]

The operating profits of the proxy CT, however, logically also should account for the revenues from ancillary services. ORA thus further reduces the MGCC below the real economic carrying cost of a CT due to the existence of "ancillary services rents" of a new CT. SCE neglected to identify and calculate ancillary service rents in their testimony and workpapers. ORA contends that, to

[4] Ex. SCE-02, p. 18
[5] Ex. SCE-02, p. 22.
[6] Ex. SCE-2, Table I-5, p. 24.

extend there were any profits from ancillary services that a utility-owned proxy CT is able to earn, when market prices for these ancillary services are above the CT's variable operating and maintenance costs, these profits (ancillary services rents) should be deducted (similar to energy rents) to reduce MGCC even further below the real economic carrying cost of a CT.

III. DISCUSSION

ORA accepts SCE's proposed conceptual framework for calculating MGCC, starting with the real annualized cost of a CT and deducting energy rent, with three exceptions.

First, the Commission historically has recognized that marginal generation capacity costs need to be reduced, relative to the full annualized cost of a combustion turbine, during periods of surplus capacity. Yet SCE proposes no such adjustment.

Second, the MGCC should be adjusted by deducting ancillary services rents in a similar manner that energy rents are deducted. This deduction is reasonable because to the extent there were any profits from ancillary services that a proxy CT is able to earn when market prices for these ancillary services are above the CT's variable operating costs, these profits should be deducted (similar to energy rents) to reduce MGCC even further below the real economic carrying cost of a CT.

Finally, ORA applied a discount rate of 7.9% (in place of SCE's proposed 10% discount rate) in the calculation of Real Economic Carrying Charge ("RECC") for generation. ORA notes that SCE applied the discount rate of 7.9% in the calculation of RECC for transmission, distribution, smart meters (20 year life), street lights, billing equipment, and capitalized software. SCE's reasoning for using a higher discount rate of 10% for generation with expected economic life of 30 years is not consistent with transmission and distribution projects' discount rate of 7.9% which are of similar economic life, if not longer.

A. Marginal Generation Capacity Costs Should Signal the Amount of Surplus Capacity and Timing of New Additions

The principle that marginal costs should signal the amount of surplus capacity and the timing of new additions was stated repeatedly by the Commission during the 1990s in an era when marginal costs were litigated rather than adopted through settlements. The Commission has applied this principle in both electric and natural gas contexts.[7] ORA is unaware of any litigated Commission decision that adopted a marginal cost based on the full annualized cost of new capacity when near-term surplus capacity was shown to be present.

The capacity costs reflected in the MGCC accordingly must be reduced when there is near-term surplus capacity. SCE's failure to adjust its MGCC accordingly runs counter a long series of Commission decisions culminating in D.96-04-050, one of the more recently litigated SCE decisions dealing with generation marginal cost issues. In D.96-04-050, the Commission reaffirmed its previous guidance that marginal costs should be reduced during times of near-term capacity surplus.

In the next two sections, ORA will establish the existence of near-term surplus generation capacity and explain in detail how it proposes to adjust SCE's MGCC proposal to reflect that surplus capacity.

B. Southern California Edison's Service Territory Will Have Surplus Generation Capacity At Least Through 2020.

The Commission utilizes a Long-Term Procurement Planning ("LTPP") process to assess generation capacity needs over a ten-year horizon. The last LTPP proceeding (R.12-03-014) was initiated in March, 2012. The 2012 LTPP was organized into four "tracks," of which Track I and Track IV are relevant here.

---

[7] In D.92-12-058, the Commission rejected a proposal to base the marginal cost of gas transmission on the annualized cost of a new pipeline. The rejected proposal was equivalent to the unadjusted RECC methodology SCE proposes here.

Track I was used to identify CPUC-jurisdictional needs for new resources to meet system or local resource adequacy and to authorize IOU procurement to meet that need. In its Decision D.13-02-015, the Commission ordered SCE to "procure between 1400 and 1800 Megawatts (MW) of electrical capacity in the West Los Angeles sub-area of the Los Angeles basin local reliability area to meet long-term local capacity requirements by 2021."[8] In addition to West LA sub-area, SCE was ordered to "procure between 215 and 290 Megawatts of electric capacity to meet local capacity requirements in the Moorpark sub-area of the Big Creek/Ventura local reliability area by 2021".[9] The ordering paragraphs were based on a finding of fact that "[t]here is a significant need for LCR resources to replace retiring OTC plants in the LA basin local area by 2021 under every ISO scenario, as well as under the Environmentally Constrained scenario sensitivity analysis."[10] It was determined that "[i]t is necessary that a significant amount of this procurement level be met through conventional gas-fired resources in order to ensure LCR needs will be met."[11] Track I did not authorize any additional procurement for PG&E and SDG&E.

Track IV was initiated in R.12-03-014 to consider additional resource needs related to the long-term outages and subsequent permanent closure of the San Onofre Nuclear Generation Station ("SONGS"). Unlike Track I, Track IV focused more narrowly on local capacity requirements in what is known as the "SONGS study area." This area consists of the entire SDG&E service area and the LA Basin portion of SCE's territory. In Track IV Decision D.14-03-004, the Commission authorized SCE to procure between 500-700 MW and SDG&E to procure between 500 and 800 MW by the end of 2021 to meet local capacity needs stemming from the retirement of the SONGS.[12]

[8] D.13-02-015, Ordering paragraph 1.
[9] D.13-02-015, Ordering paragraph 2.
[10] D.13-02-015, Finding of Fact 27.
[11] D. 13-02-015, Finding of Fact 30.
[12] D.14-03-004, Ordering paragraph 1 and 2.

Based on Commissions decisions in Track I and Track IV of the 2012 LTPP, ORA concludes that the Commission authorized SCE to procure new resources by at least January 1, 2021 due to (1) Projected retirements of once-through cooling ("OTC") power plants to meet State Water Resources Control Board's OTC policy compliance deadline of December 31, 2020, and (2) The premature permanent closure of SONGS. Because the new resources need to be operational by 2021, it is logical to assume that the specified new generation capacity will not be needed in SCE's service territory in any of the years leading up to 2021.

Further confirmation of this capacity surplus can be found in a recent independent (non-Commission sponsored) report by the North American Electric Reliability Corporation ("NERC"). NERC examined the resource balance for each of the major sub-regions within the Western Electricity Coordinating Council ("WECC") region. NERC's analysis concludes that:

> … the reserve margins for the WECC subregions remain above the Reference Margin Levels through 2021. Beginning in 2022, individual subregions do drop below their Reference Margin Levels, but the potential resource additions that have been reported exceed these possible shortages.[13]

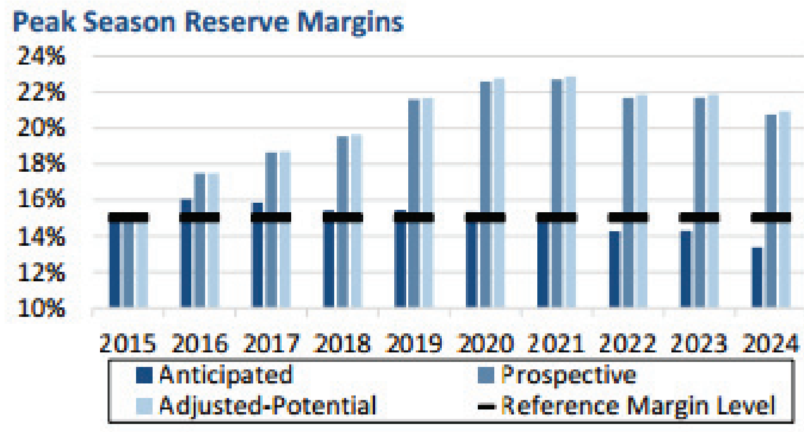
The following figure[14] summarizes NERC's findings for WECC's California sub-region.

---

[13] NERC 2014 Long-Term Reliability Assessment, November 2014, p. 92.

[14] North American Electric Reliability Corporation (NERC) 2014 Long-Term Reliability Assessment, November 2014, p. 90.

Figure 4-1



The report does not break down CA's sub-region into individual investor-owned utilities' service territories.

C. SCE's MGCC Should Be Estimated Based on the Value of Deferral of Capacity from 2020 to 2021.

As discussed above, 2020 is the soonest that new generation capacity could be needed for reliability purposes in California. Further, 2020 is the last year of the six-year period which begins 2015. The Commission has traditionally adopted a six-year period for estimating MGCC because it balances short-run and long-run capacity needs. For these reasons, ORA bases its MGCC estimate on a scenario that capacity will not be needed during the years 2015 through 2020. But it will be needed after 2020 based on Commission's 2012 LTPP Decision, which requires that new generation resources be operational by January 1, 2021 in SCE's service territory.

Accordingly, ORA proposes to modify SCE's proposed RECC methodology by escalating the CT cost to 2020, and then computing the present value in 2015 of the annualized cost of a CT installed in 2020 to be consistent with a six-year period. Escalating the CT cost to 2020 by the inflation rate of 1.77%, and then discounting the CT cost by 7.9% discount rate, ORA finds that the GRC Marginal Cost Capacity Value should be adjusted by a time value of money discount factor of 0.746. This is equivalent to a reduction of about 25.4%.

Incorporating ORA's adjustments to SCE's discount rate from 10% to 7.9%, and deducting ancillary services rents, the effect of the assumed five-year delayed CT installation from 2015 to 2020 reduces ORA's estimate of 2015 MGCC from $97.51/kW-year to $72.8/ kW-year.[15]

ORA's proposed method is consistent with marginal cost theory, as articulated by Alfred Kahn. Kahn, in describing a situation in which lumpy investments in capacity occur in anticipation that they will be needed to satisfy future peak demands, states the following:

> Typically, public utility companies must build in advance of demand in order to be in a position to meet unexpected peak requirements and simply because the investment process is a lumpy one: additions to capacity are most economically made in large units. Therefore at any given time, there is almost certain to be excess capacity, which will remain idle if customers are charged long-run marginal costs.[16]

Kahn then asks, rhetorically: "What, in these circumstances, is the proper measure of marginal costs?" He answers his own question thusly:

> …there is a strong economic case for letting price rise and fall as demand shifts…in the presence of excess capacity, no matter how temporary, no business should be turned away that covers the SRMC [short run marginal cost] of supplying it.[17]

Kahn describes in a footnote how capacity costs could be assigned to current peak period usage even though such usage is not causing an immediate need for new capacity:

> It might appear that no customer whose continued patronage would eventually require additions to capacity should ever be charged a price that completely excludes those capital costs; the economic

---

[15] This values excludes the 15% resource adequacy adder. Incorporating the 15% RA adder produces ORA's final estimate of 2015 MGCC of $83.71/kW-year.

[16] Kahn, Alfred, The Economics of Regulation (1970), p. 104. (see http://mitpress.mit.edu/books/economics-regulation.)

[17] Id at p. 104.

ideal, it might appear, would be to include them, but **discounted back to the present value**, to reflect the fact that continued service of the customer in question would require their incurrence only sometime in the future.[18]

In the current context, therefore, ORA believes that it is entirely consistent with economic theory, when near-term surplus capacity exists, to charge current on-peak electricity users a substantial fraction, but not 100%, of the full long-run cost of capacity. ORA proposes to use the traditional RECC approach applied to a CT proxy installed in 2020, but discounted back to the present value as described by Kahn.[19] For the 7.9% discount rate utilized by ORA, and 1.77% inflation rate proposed by SCE, discounting back to the present value results in about a 25.4% reduction, from $97.51/kW-year to $72.8/kW-year.

D. SCE's MGCC Should Take into Account Estimated Ancillary Services Rents

SCE's estimate of MGCC should not only be reduces by energy rents but also by ancillary services rents, which SCE neglected to identify and calculate in their testimony and workpapers. SCE's analysis and workpapers of the Simple Cycle GE 7FA unit assumes a utility ownership structure.[20] In response to ORA's data request on whether SCE would retain all the energy and ancillary services

---

[18] Kahn, Alfred, The Economics of Regulation (1970), p. 104, footnote 47, emphasis added. The reader may note the phrase "it might appear." This caveat refers to the subsequent statement (in the same footnote): *"Such a prescription ignores the fact that buyers whose continued patronage could require the incurrence of additional capacity costs are not in fact responsible for them if they drop out of the market when the time comes for the supplying company to make the decision whether to make the additional investment."*
ORA believes that Kahn's caveat does not apply, in the main, to electricity, because most electrical equipment has an expected lifetime of five years or more, and so, any change in current electricity consumption due to acquisition of new or replacement electrical equipment or appliances is likely to be of long duration and is likely, therefore, to affect future capacity needs.

[19] Id. The necessary adjustment is given by the formula: Y = X (1+i)^n/(1+r)^n where Y is the adjusted capacity value, X is the unadjusted capacity value proposed by SCE, i is the inflation rate, r is the discount rate, n is the number of years elapsed (5, in this case) between the test year and the year of capacity need), and "^" denotes exponentiation.

[20] Data Request 10, Question 1.

revenues in the event SCE's utility owned generation's bids were selected by CAISO, SCE replied:

> For SCE's utility owned generation (UOG), all market revenues, such as those from energy and ancillary service market awards, go into the Energy Resource Recovery Account (ERRA). Essentially, these market revenues offset market costs incurred on behalf of SCE's customers, and the net costs are then recovered from customers.[21]"

ORA proposes to use $3.83/kW-year as an estimated value of ancillary services rents for a CT proxy. ORA derived this value by referencing the Table[22] below:

Figure 4-2

Table 1.10 Financial analysis of new combustion turbine (2010-2013)

Components	2010		2011		2012		2013	
	NP15	SP15	NP15	SP15	NP15	SP15	NP15	SP15
Capacity Factor	7%	10%	6%	7%	5%	8%	8%	9%
Energy Revenue ($/kW - yr)	$64.97	$95.94	$57.60	$69.57	$48.78	$78.89	$58.48	$82.95
A/S Revenue ($/kW - yr)	$3.36	$2.97	$6.06	$5.98	$4.29	$5.04	$1.14	$1.34
Operating Cost ($/kW - yr)	$24.80	$35.60	$23.23	$26.88	$14.82	$23.62	$38.03	$42.85
Net Revenue ($/kW - yr)	$43.54	$63.32	$40.43	$48.67	$38.26	$60.32	$21.59	$41.45
5-yr Average ($/kW - yr)	*$35.96*	*$53.44*						

After performing basic analysis, ORA determined that the average ancillary services revenues was $3.83/kW-year, while the average energy revenues was $81.84/kW-year between 2010-2013 years in CAISO's SP-15 zone.[23] The average ancillary services revenues constituted about 4.68% of the average energy revenues. ORA did not modify the $3.82/kW-year number to account for any costs because combustion turbines typically provide spin and non-spin ancillary

[21] Data Request 10, Question 2.

[22] CAISO's Department of Market Monitoring *2013 Annual Report of Market Issues & Performance*. (See http://www.caiso.com/Documents/2013AnnualReport-MarketIssue-Performance.pdf)

[23] The values of $81.84 and $3.83 are simple averages, and no conversion is made for the time value of money. The 5-year averages already included in the last line of the table are calculated the same way..

services.[24] The incremental costs associated with these services are negligible when compared to the marginal cost of energy that is simultaneously bid into the CAISO market. That marginal cost of energy would include the cost of gas multiplied by a heat rate and variable operating and maintenance ("O&M") cost.

Furthermore, ORA finds that its estimate of $3.83/kW-year, which can be interpreted as 4.68% of average energy revenues of $81.84/kW-year, is conservative when compared to the ancillary service revenues from SCE's five peaker units over a three-year period. Based on ORA's data request to SCE, ORA determined that the total ancillary services revenues constitute about 6.3%[25] of the total energy revenues for SCE's five peaker units from November 2011 until November 2014.

Therefore, ORA contends, that to extend there were any profits from ancillary services that a utility-owned proxy CT is able to earn, when market prices for these ancillary services are above the CT's variable O&M costs, these profits (ancillary services rents) should be deducted (similar to energy rents) to reduce MGCC even further below the real economic carrying cost of a CT.

E. SCE's MGCC Calculations Should be Adjusted by a 7.9% Discount Rate Instead of SCE's Proposed 10% Discount Rate

Finally, ORA applied a discount rate of 7.9% (in place of SCE's proposed 10% discount rate) in the calculation of RECC for generation. ORA notes that SCE applied the discount rate of 7.9% in the calculation of RECC for transmission, distribution, smart meters (20 year life), street lights, billing equipment, and capitalized software.

---

[24] Effectively, ORA assumed that ancillary services revenues are equal to ancillary services rents (profit).

[25] Data Request 10, Question 5. The reader may note that based on SCE's response, *SCE does not own 1 unit simple cycle GE 7FA turbines (based on which the MGCC is being performed). SCE owns 5 LM 6000 peaker plants that are significantly smaller than the GE 7FAs.*

In response to ORA's data request, asking why the value SCE used as an input assumption to derive the RECC and discount rate of 7.9% is different from the incremental cost of capital assumption of 10% for generation, SCE explained:

> SCE utilizes two cost of capital percentages as inputs to RECC Marginal Cost Capacity. For Distribution Marginal Cost Capacity, SCE utilizes the weighted average cost of 7.9%, which was authorized by the Commission in D.12-13-034. This value is used to reflect the cost of existing financing. For Generation Marginal Cost, SCE applied an incremental cost of capital of 10%. The 7.9% weighted average cost of capital is not an input to the 10% incremental cost of capital. The incremental cost of capital is representative of SCE's forward-looking long-term cost of capital, which is more consistent with the forecast window being assessed in SCE's Generation Marginal Cost.[26]

ORA examined SCE's workpapers and found that SCE is assuming that 1 Unit Simple Cycle GE 7FA's economic life is thirty years. Based on SCE's response to ORA's data request[27], SCE provided FERC Account Assumptions for Carrying Charge Rates where the book life of various transmission plant accounts varied between 40 and 60 years. Meanwhile, the book life of various distribution plant accounts varied between 30 and 55 years, with one exception for smart connect meters, for which the book life was 20 years. The book life for various transmission accounts is consistent with CAISO's financial parameters used in cost-benefit analysis in their annual 2014-2015 transmission plan. In calculating the total cost in the cost analysis, CAISO used 50 years for asset depreciation horizon with a cost discount rate ranging from 7% (real) to 5% (real). Meanwhile for calculating yearly benefits for use in the total benefit, CAISO used 50 years for economic life of new transmission facilities with a benefits discount rate ranging from 7% (real) to 5% (real).[28]

---

[26] Data Request, Verbal 03.

[27] Data Request 7, Question 1b.

[28] Draft 2014-2015 Transmission plan pp. 234-235.

ORA disagrees with SCE's reasoning for using a higher discount rate of 10% for generation because the expected economic life of 30 years is not consistent with that of transmission and distribution projects. The latter have similar, if not longer, economic lives. A longer economic life implies a higher risk premium and should have a higher discount rate. Therefore, the discount rate for the generation asset should be no greater than the discount rate for transmission and distribution.

F. Comparison of SCE's and ORA's Proposed MGCC Values

The following table compares SCE's and ORA's marginal generation cost of capacity values line item by line item.

TABLE 4-1:

COMPARISON OF SCE AND ORA PROPOSED MGCC VALUES

Incremental Capacity Cost (Values are in year beginning 2015 %, unless otherwise specified	**SCE**	**ORA**
1. Instant Cost (2015 $)	**807**	**807**
2. AFUDC	81	64*
3. Turn Key Cost (2015 $)	**888**	**871**
4. Real Economic Carrying Charge	11.16%	9.25%*
5. Annualized CT Installed Cost (3 * 4)	**99.10**	**80.57**
6. Property Tax (loading)	6.94	6.34*
7. Total Capital Cost including loadings	**106.04**	**86.91**
8. Fixed O&M (2015 $)	9.69	9.69
9. Incremental Capacity Cost (end of year discounting)	115.7	96.9
10. Incremental Capacity Cost (mid-year discounting adjusted)	**121.38**	**100.34**
11. Energy Rents (NPV over life of plant)	53.30	53.30
12. Annualized Value of Energy Rents (4 * 11) (mid-year adjusted)	**6.24**	**5.12**
13. Ancillary Services Rents	-	3.83
14. Incremental Capacity Value (mid-year) (line 10-12-13)	**115.14**	**91.39**

15. General Plant Loader (line 14 * 6.7%)	7.7	6.1
16. GRC Marginal Cost Capacity Value (mid-year)	**122.85**	**97.51**
17. Year of Need	2015	2020
18. Time Value of Money Discount Factor	1	0.746**
19. GRC Marginal Cost of Capacity (mid-year) Adjusted for Time Value of Money	**122.85**	**72.79**
20. RA Planning Reserve Margin Adder	15%	15%
21. GRC Marginal Cost of Capacity	**141.28**	**83.71**
*AFUDC, RECC and Property Tax were impacted by the change in the discount rate from 10% to 7.9%. Consequently, the changes were propagated to other values. ** The TVM Discount Factor was impacted by the change in discount rate to 7.9%.		

IV. CONCLUSION

The Commission should adopt SCE's marginal generation capacity costs with the adjustments proposed by ORA to reflect that fact that no additional generation capacity will be needed by California utilities for reliability before 2021. In addition, the Commission should consider deductions for ancillary services rents proposed by ORA and adjust SCE's discount rate to 7.9% instead of 10% as proposed by SCE in determining the marginal cost of capacity.

CHAPTER 5

REVENUE ALLOCATION

CHERIE CHAN

TABLE OF CONTENTS

CHAPTER 5

REVENUE ALLOCATION

CHERIE CHAN

I. SUMMARY AND RECOMMENDATIONS

This chapter addresses the revenue allocation proposals of the Office of Ratepayer Advocates ("ORA") in the SCE GRC[1] Phase II proceeding. Below, ORA provides its analysis of SCE's proposals for allocating generation, distribution, and other revenue requirements to customer groups, as well as ORA's recommendations. ORA recommends the Commission:

- Adopt ORA's Marginal Cost Recommendations to allocate revenue responsibilities,
- Continue the use of caps so that no one class would face a rate increase disproportionately above the system average rate percent change.

The impact of ORA's recommendations on SCE's revenue allocation are summarized in Table 5-1 below.

[1] Southern California Edison ("SCE") General Rate Case ("GRC").

TABLE 5-1: ORA VS. SCE

BUNDLED AVERAGE RATES BY RATE GROUP

	ORA Table I-7 Proposed Bundled Service Average Rates By Rate Group (¢/kWh)					SCE Table I-7		
	April 2014 (¢/kWh)	% of SAR	Proposed (¢/kWh)	% of SAR	% Change	Proposed (¢/kWh)	% of SAR	% Change
Total Domestic	16.3	105%	16.2	104%	-0.8%	16.7	107%	2.2%
GS-1	18.1	116%	16.2	104%	-10.6%	17.2	110%	-5.3%
TC-1	18.4	118%	15.1	97%	-17.5%	19.8	127%	8.1%
GS-2	17.7	113%	17.2	111%	-2.6%	17.3	111%	-1.8%
TOU-GS-3	15.6	100%	16.2	104%	3.8%	15.4	99%	-1.1%
Total LSMP	17.2	110%	16.7	108%	-2.8%	16.8	108%	-2.3%
TOU-8-Sec	14.3	92%	14.8	95%	3.6%	13.9	89%	-3.0%
TOU-8-Pri	12.9	83%	13.8	89%	7.2%	12.7	82%	-1.1%
TOU-8-Sub	8.8	57%	9.6	62%	8.1%	9.2	59%	3.7%
Total Large Power	12.3	79%	13.0	84%	5.6%	12.2	78%	-1.0%
TOU-PA-2	14.9	96%	14.5	93%	-2.4%	15.3	98%	2.9%
TOU-PA-3	11.5	74%	13.7	88%	18.5%	12.8	82%	11.2%
Total Ag.&Pumping	13.5	87%	14.2	91%	4.8%	14.3	92%	5.8%
Total Street Lighting	18.0	115%	18.5	119%	3.2%	18.7	120%	3.9%
STANDBY/SEC	14.0	90%	14.3	92%	2.3%	13.4	86%	-3.9%
STANDBY/PRI	13.8	89%	14.5	93%	5.0%	13.4	86%	-2.8%
STANDBY/SUB	9.5	61%	10.1	65%	6.8%	9.8	63%	3.2%
Total Standby	10.8	69%	11.4	73%	5.8%	10.9	70%	0.8%
Total System	15.6	100%	15.5	100%	-0.2%	15.6	100%	0.2%

Note that the above recommendations do not include ORA's proposal to apply caps to mitigate large rate swings. The capping functionality is not working in SCE's most recent revenue allocation spreadsheet model, but ORA is continuing to work with SCE to restore that functionality to SCE's revenue allocation workpapers.

II. APPLICANT'S PROPOSALS

A. SCE's Marginal Cost Revenue Allocation

Revenue allocation is a process of assigning to each customer class a portion of the utility's revenue requirement. The Commission has utilized marginal cost-based revenue allocation since the late 1970s. This process starts with calculating marginal costs for two utility functions (generation and distribution).

Then the cost responsibility for these two functions is assigned to classes based on the proportion of each class' marginal cost revenue[2] relative to the total system marginal cost revenues. In D.97-08-056, the Commission adopted a policy to allocate costs separately. This process calculates the separate revenue requirements for generation and distribution. Those revenues then are allocated on an unbundled basis by using the separate marginal cost revenues for each function. Accordingly, each customer class' revenue responsibility is determined based on the marginal cost revenue assigned to the class. The latter then is scaled up to match the revenue requirement for each of the functions.[3]

In this proceeding, SCE proposes to continue using this functional marginal cost allocation established in D.97-08-056. ORA concurs with this general approach. However, it uses its own marginal costs which are discussed in chapters 1—3 of ORA's opening testimony. The individual and overall effects of these recommendations on ORA's overall revenue allocation are discussed in detail in section III.A below.

B. SCE's Uncapped Proposals Result in Wide Variations in Average Rates per Class

SCE's proposed Phase II revenue allocation begins with a System Average Rate ("SAR") that is "revenue neutral" in that it does not reflect any changes to rates that are expected from Phase 1 of this GRC cycle. Thus, any Phase II increases or decreases in a class' revenue responsibility will be added on top of the system-wide increase approved in Phase I. However, SCE's SAR does include a small subset of revenue requirement increases[4] relative to the April 2014 SAR that are outside the scope of the GRC Phase 1 outcome. Thus, the SAR is expected to

[2] This is the product of the class' marginal cost and the relevant billing determinant.

[3] This process is called equal percent marginal cost ("EPMC") to scale marginal cost revenues up or down to match the revenue requirements.

[4] Incorporating the current DWR Reserve Bond revenue requirements credit and transmission balancing account adjustments. Exh. SCE-03, page 22.

increase 0.08 percent over the April 2014 SAR from 15.57¢/kWh to 15.60¢/kWh. Including this small SAR change, SCE proposes that residential customers would receive an overall increase of 2.2 percent from 16.30¢/kWh to 16.66¢/kWh, and Small Commercial customers would see their rates drop from 18.1¢/kWh to 17.2¢/kWh.[5]

SCE's current uncapped proposal would result highly uneven changes across customer classes. While SCE does not explicitly argue against capping increases and decreases in its testimony, it does not propose them either, and further notes that its results produce "average rate impacts ranging from -4.8 percent to 11.2 percent." It further explains that "the variation around the system average rate for individual rate groups is primarily the result of the movement towards full cost-based allocation from current rates."[6]

To address the wide deviations from the System Average Rate amongst groups as shown in Table 5-1, ORA proposes that SCE's proposal be modified to include caps as has been done in many previous GRCs, and as was approved in SCE's most recent GRC decision 13-03-031. These caps should be adopted to promote rate stability and bill predictability and mitigate rate swings. As discussed in Section III.C below, ORA was not able to implement this proposal in SCE's newest revenue allocation spreadsheets but has been working with SCE to restore this functionality to SCE's revenue allocation model.

---

[5] SCE Supplemental Workpapers supporting Table I-7, received January 27, 2015. Note that the numbers used by ORA do not exactly match those used in SCE's written testimony filed June 20, 2014 nor its Errata, filed January 23, 2015. SCE filed "Phase 2 of 2015 General Rate Case ERRATA to Direct Testimony" labeled SCE-07 as well as "Phase 2 of 2015 General Rate Case Supplemental Testimony re: Standby Rate Design" labeled SCE-08 on January 23, 2015. Accompanying workpapers were sent to ORA January 26th which matched the Errata testimony, but these were superseded by new Revenue Allocation workpapers—on which ORA bases its Revenue Allocation Testimony—received January 27th, which included the changes to Standby rates that flowed through as changes to the overall revenue allocation as described in Exhibit SCE-08.

[6] SCE page 23, lines 2-4.

III. DISCUSSION & ORA'S PROPOSALS

A. ORA's Marginal Cost Recommendations

ORA recommends that the Commission adopt ORA's Marginal Cost proposals, as detailed in Chapters 1—3 of its testimony. The effects of these proposals are summarized below:

1) Marginal Customer Costs:
   a) Adopt ORA's NCO method along with ORA's revised Customer Access Marginal Costs for Revenue Allocation, reducing the allocation to the Domestic Class by $69.36 million and Small Commercial Class by $44.78 million.
2) Marginal Distribution Demand Costs:
   a) Increase SCE's Design Demand Distribution Marginal Cost from $89.29/kW to $99.90/kW, saving the Domestic Class $7.29 million and Small Commercial Customers $1.72 million.
   b) Increase SCE's Design Demand Non-ISO Sub Transmission Marginal Cost from $37.58/kW to $29.92/kW, increasing the allocation to the Domestic Class $9.48 million and Small Commercial Customers $3.77 million.
3) Marginal Generation Energy Costs:
   a) Reduce the Annual Generation Capacity value from 141.29 kW-year to 83.71 kW-year, reducing the allocation to the Domestic Class by $74.1 million and to Small Commercial Customers by $1.72 million.[7]

The result of adopting each of ORA's Marginal Cost Proposals are shown in the table below, both individually as well as cumulatively as a percent change for each marginal cost factor.[8]

---

[7] In Chapter 4, Synapse confirms SCE's marginal energy cost methodology, and made very minor modifications to the overall costs. ORA ran the results of Synapse's revised marginal costs in SCE's Revenue Allocation model, but the results were immaterial, adding 0.01% to the residential allocation, and maintaining the same allocation to GS-1.

[8] This table is labeled according to ORA naming conventions, but is analogous to SCE's table I-1 in SCE-03 representing its proposed 2015 retail system revenue requirement by revenue component prior to adjustments for revenue allocation. ORA breaks out the Revenue Allocation effects of each marginal cost recommendation to aid in measuring the affects by class of each marginal cost recommendation per class. Workpapers are available upon request.

TABLE 5-2: ORA MARGINAL COST RECOMMENDATIONS AND THEIR PERCENTAGE EFFECTS ON REVENUE ALLOCATION

Exh. SCE-03 Table I-1 (ORA)

System Retail Services - Revenue Allocation

($ Millions)

Chapter		1 Customer MC		2 Distribution MC		2 Distribution MC Non-ISO		3 Gen./Cap.		5 All ORA Marginal Cost	
Change	SCE	Change MCAC		Distribution (12)		SubTrans.(66)		↓Annual Gen			
MCCR Cell Reference	(Supp.)	Column M		D19		D18		K15			
SCE Input		Varies		89.3	Updated	37.6	Updated	141.3			
ORA Input				99.9		29.9		83.7			
	SCE		% Δ		% Δ		% Δ	New	% Δ		% Δ
Total Domestic	**5158.0**	**5088.6**	**-1.34**	**5150.7**	**-0.14**	**5167.5**	**0.18**	**5083.9**	**-1.44**	**5017.3**	**-2.73**
GS-1	**796.4**	**751.6**	**-5.62**	**793.1**	**-0.41**	**799.8**	**0.43**	**794.7**	**-0.22**	**750.4**	**-5.78**
TC-1	11.7	8.6	-26.49	11.5	-1.98	11.9	1.72	11.9	1.99	8.8	-24.63
GS-2	2378.0	2350.5	-1.16	2377.3	-0.03	2380.4	0.10	2384.5	0.27	2359.3	-0.79
TOU-GS-3	1065.5	1116.6	4.80	1070.5	0.47	1062.6	-0.27	1073.0	0.70	1126.4	5.71
Total LSMP	4251.6	4227.3	-0.57	4252.5	0.02	4254.7	0.07	4264.1	0.29	4244.9	-0.16
TOU-8-Sec	965.1	1020.3	5.71	970.9	0.60	962.3	-0.29	979.3	1.47	1037.8	7.53
TOU-8-Pri	565.9	604.7	6.86	570.1	0.75	564.5	-0.24	576.7	1.92	618.9	9.37
TOU-8-Sub	433.6	443.7	2.33	431.1	-0.59	426.2	-1.71	449.8	3.74	447.6	3.23
Total Large Power	1964.6	2068.7	5.30	1972.1	0.38	1953.1	-0.59	2005.8	2.10	2104.3	7.11
TOU-PA-2	258.5	242.0	-6.37	257.7	-0.32	259.7	0.47	260.3	0.69	244.4	-5.44
TOU-PA-3	146.2	151.5	3.61	146.8	0.41	146.1	-0.06	150.1	2.67	156.0	6.68
Total Ag.&Pumping	404.7	393.5	-2.77	404.5	-0.05	405.8	0.28	410.4	1.41	400.4	-1.06
Total Street Lighting	137.0	129.6	-5.43	136.5	-0.40	137.5	0.34	143.4	4.64	135.9	-0.82
STANDBY/SEC	27.3	28.6	4.51	27.5	0.47	27.3	-0.26	27.9	2.07	29.2	6.82
STANDBY/PRI	75.4	80.5	6.72	76.0	0.76	75.3	-0.18	76.8	1.77	82.3	9.16
STANDBY/SUB	168.1	170.0	1.16	167.1	-0.55	165.7	-1.41	174.6	3.86	172.5	2.61
Total Standby	270.8	279.1	3.05	270.6	-0.08	268.3	-0.95	279.2	3.10	284.0	4.86
Total System	12186.8	12186.8	0.00	12186.8	0.00	12186.8	0.00	12186.8	0.00	12186.8	0.00

To demonstrate the dollar effects of ORA's marginal cost Recommendations, ORA includes an additional table below. As with the previous table, this data is analogous to SCE's Table I-1.[9]

[9] From Exh. SCE-03.

TABLE 5- 3: ORA MARGINAL COST RECOMMENDATIONS AND THEIR DOLLAR EFFECTS ON EACH CLASS

Exh. SCE-03 Table I-1
System Retail Services - Revenue Allocation
($ Millions)

Chapter		1 Customer MC		2 Distribution MC		2 Distribution MC Non-ISO		3 Gen./Cap.		5 All ORA	
Change	SCE	Change MCAC		Distribution (12)		SubTrans.(66)		↓Annual Gen		Marginal Cost	
MCCR Cell Reference	(Supp.)	Column M		D19		D18		K15			
SCE Input		Varies		89.3	Updated	37.6	Updated	141.3			
ORA Input				99.9		29.9		83.7			
	Original		$ Δ		$ Δ		$ Δ		$ Δ		$ Δ
Total Domestic	5,158.0	5,088.6	-69.4	5150.7	-7.3	5,167.5	9.48	5083.9	-74.1	5017.3	-140.7
GS-1	796.4	751.6	-44.8	793.1	-3.3	799.8	3.44	794.7	-1.7	750.4	-46.0
TC-1	11.7	8.6	-3.1	11.5	-0.2	11.9	0.20	11.9	0.2	8.8	-2.9
GS-2	2,378.0	2,350.5	-27.6	2377.3	-0.7	2,380.4	2.35	2384.5	6.5	2359.3	-18.7
TOU-GS-3	1,065.5	1,116.6	51.1	1070.5	5.0	1,062.6	-2.93	1073.0	7.5	1126.4	60.9
Total LSMP	4251.6	4,227.3	-24.3	4252.5	0.8	4,254.7	3.06	4264.1	12.5	4244.9	-6.8
TOU-8-Sec	965.1	1,020.3	55.1	970.9	5.8	962.3	-2.80	979.3	14.2	1037.8	72.7
TOU-8-Pri	565.9	604.7	38.8	570.1	4.2	564.5	-1.35	576.7	10.8	618.9	53.0
TOU-8-Sub	433.6	443.7	10.1	431.1	-2.5	426.2	-7.41	449.8	16.2	447.6	14.0
Total Large Power	1,964.6	2,068.7	104.1	1972.1	7.5	1,953.1	-11.57	2005.8	41.2	2104.3	139.7
TOU-PA-2	258.5	242.0	-16.5	257.7	-0.8	259.7	1.21	260.3	1.8	244.4	-14.1
TOU-PA-3	146.2	151.5	5.3	146.8	0.6	146.1	-0.09	150.1	3.9	156.0	9.8
Total Ag.& Pumping	404.7	393.5	-11.2	404.5	-0.2	405.8	1.13	410.4	5.7	400.4	-4.3
Total Street Lighting	137.0	129.6	-7.4	136.5	-0.5	137.5	0.47	143.4	6.4	135.9	-1.1
STANDBY/SEC	27.3	28.6	1.2	27.5	0.1	27.3	-0.07	27.9	0.6	29.2	1.9
STANDBY/PRI	75.4	80.5	5.1	76.0	0.6	75.3	-0.14	76.8	1.3	82.3	6.9
STANDBY/SUB	168.1	170.0	1.9	167.1	-0.9	165.7	-2.36	174.6	6.5	172.5	4.4
Total Standby	270.8	279.1	8.3	270.6	-0.2	268.3	-2.57	279.2	8.4	284.0	13.2
Total System	12,186.8	12,186.8	0.0	12,186.8	0.0	12,186.8	0.00	12186.8		12,186.8	0.0

B. Caps Should Continue to be Adopted to Promote Rate Stability and Mitigate Swings

The Commission has traditionally adopted capping rate increases so that no one customer class will see rate increases more than a set percentage above or below the System Average Rate of Increase. ORA agrees with this policy, though the size of the ORA's recommended caps has varied depending on the specific conditions and the outcomes of the pending GRC phase 1 revenue requirement requests[10]. SCE does not explicitly argue for a rate cap in this proceeding, nor does it argue against one. In this proceeding, ORA continues its support of the Commission's policy to use caps in the revenue allocation process to moderate rate increases, and proposes that SCE's models be updated to support caps to limit the overall changes to any one class to mitigate bill impacts that occur with large changes, particularly swings in the revenue allocation.

1. Commission Precedent Supports Caps

In SCE's 1995 GRC Phase II Decision (D.96-04-050), the Commission provided an extensive discussion of the policy of capping, including a number of proceedings where capping was adopted.

> "In the past, we have capped full movement to 100% EPMC in order to mitigate harsh bill impacts. In Edison's last GRC, we determined that average rate increases of approximately 20% to the agricultural and pumping class should be mitigated by imposing a cap of SAPC plus 3.5%. In Edison's test year 1988 GRC, we capped full EPMC revenue allocation by SAPC plus 5% to mitigate increases to the domestic class of a similar magnitude. (D.87-12-066 26 CPUC 2d 392, 528-529; D.92-06-020, 44 8 CPUC 2d 471, 496-497.)"

Most recently, D.13-03-031 approving SCE's Settlement Agreement also encouraged the "Capping of allocated revenues to rate groups to promote rate stability while achieving movement toward cost-based rate structures."[11]

2. ORA Supports SCE's Continuing Efforts to Implement the Capping Functionality in its Workpapers

ORA has worked cooperatively with SCE's revenue allocation team to implement caps using SCE's Revenue Allocation and Rate Design model. However, the latest iteration[12] of SCE's workpapers do not allow for caps at this

---

[10] ORA advocated for a cap of 5% in A.11-06-007, SCE's 2012 GRC Phase 2 Proceeding. ORA also supported PG&E's most recent proposed cap of +/-3% for bundled service customers and +/-6% for DA/CCA customers.

[11] D.13-03-031, page A-6, or 109 in the electronic .PDF file.

[12] SCE Supplemental Workpapers, received January 27, 2015 supporting SCE-08.

time, as it is not SCE's policy to implement caps, and changes to the standby rates introduced with SCE-08 make the implementation of caps impractical at this time. ORA understands that SCE will continue its work with ORA and other interested parties moving forward to re-implement the capping functionality in time for meaningful settlement discussions. In the meantime, ORA continues to support the Commission's policy of implementing caps to promote rate stability.

IV. CONCLUSIONS

In conclusion, ORA recommends that all of its Marginal Cost and Revenue Allocation recommendations as summarized in Table 5-1 be adopted. To promote stable rates and mitigate swings between GRC cycles, ORA further recommends that caps be applied when possible to ensure stability and predictability in rates for all classes.

CHAPTER 6

RESIDENTIAL RATE DESIGN

LEE-WHEI TAN

TABLE OF CONTENTS

CHAPTER 6
RESIDENTIAL RATE DESIGN
LEE-WHEI TAN

I. SUMMARY AND RECOMMENDATIONS

This chapter presents the Office of Ratepayer Advocates' ("ORA") recommendations for Southern California Edison Company's ("SCE's") residential rate design. The majority of SCE's residential rate design issues either are pending before the Commission in Rulemaking 12-06-013, which is the Residential Rate Reform Order Instituting Rulemaking ("RROIR"), or have been resolved in SCE's 2014 Rate Design Window ("RDW") Application 13-12-015. In this general rate case ("GRC"), a single issue remains, and that is SCE's proposal to establish separate baseline allowances for all-electric customers living in single-family homes versus multi-family homes.

SCE's proposal regarding baseline allowances to be inadequately justified. SCE's residential customers already are facing numerous changes through the RROIR process, making this change an unnecessary complication at this time. In addition, the RROIR will result in many residential rate structural changes, while the GRC will further impact residential rates due to the marginal cost and the class cost responsibility changes. Therefore, there are multiple layers of modifications associated with implementing the final GRC rates, which likely will come after a decision is issued in the RROIR. It is important that the parties are afforded adequate time to review SCE's rate implementation advice letter ("AL") in this GRC.

Accordingly, ORA recommends:

- The Commission reject SCE's request to reduce the all-electric multi-family baseline allowance.
- SCE's implementation of the RROIR rates and the rate changes resulting from this GRC should be well coordinated and provide other parties ample time to review the combined impacts.

II. APPLICANT'S PROPOSALS

SCE notes that the majority of its residential rate design proposals are pending in the ongoing RROIR. Those proposals include:[1]

- Increasing over time the fixed charges for California Alternate Rates for Energy ("CARE") and non-CARE customers to the statutory maximum allowed by Assembly Bill ("AB") 327.
- Providing a CARE discount equal to 30 percent of the volumetric energy rates and 50 percent of the fixed charge relative to non-CARE customers.
- Reducing over time the number of tiers on the default residential schedule (Schedule D) from four to two.
- Changing the delivery of the Family Electric Rate Assistance ("FERA") discount to a flat percentage discount off the customers' bills in light of the tier collapsing proposal.
- Reducing the rate ratio between tiers and reducing the baseline allowance from 53 percent to 50 percent
- Adopting an opt-in, non-tiered residential time-of-use ("TOU") rate with an option for low usage customers and an option for high-usage customers (each with a different fixed charge). A basic rate design structure was adopted in the recent SCE 2014 RDW, but it will need to be modified to incorporate other RROIR proposals.

As previously stated, SCE also proposes to establish separate baseline allowances for all-electric customers living in single family homes versus multi-family homes in this GRC. Currently, there is no distinction between single-family and multi-family homes for purposes of setting the baseline allowance.[2]

SCE noted[3] that the last baseline rulemaking (R.01-05-047) established the following criteria for evaluating proposed changes to utility baseline programs:

- A proposal should be tailored to meet identified needs for rate relief while avoiding unnecessary revenue loss;
- Implementation and other administrative costs should be reasonable relative to the expected rate relief;

[1] Exh. SCE-04, p.24.

[2] Exh. SCE-04, p. 27.

[3] Exh. SCE-04, p.31.

- The burdens on non-participants should be reasonable;
- Any inconsistencies in the treatment of customers or among utilities should be reasonable;
- The program should be understandable to customers; and
- It should be practical to administer.

SCE argued that its baseline proposals are aimed at creating greater equity in light of the fact that single-family and multi-family households have very different basic energy needs, and SCE's all-electric customer population is weighted in favor of multi-family customers. SCE's proposal would remove an alleged burden that is unfairly placed on single-family all-electric households. The proposed changes in baseline allowances are revenue neutral to the residential class and thus are not expected to result in any revenue losses.[4]

III. DISCUSSION & ORA'S PROPOSALS

A. Baseline Adjustment for All-Electric Usage Customers.

ORA opposes SCE's proposed change to baseline.

1. SCE Provides Inadequate Support for the Need to Change Baseline Allowances

SCE has not demonstrated that its proposal is tailored to meet identified needs for the rate relief, as directed by the Baseline Rulemaking criteria. The table below shows that, for all-electric customers, multi-family usage is roughly 54% of the single family usage, which is in line (actually smaller) with the usage pattern for families using both electric and gas utilities. It is not clear that there is a need for relief all-electric single families.

[4] Exh SCE-04, p.31

TABLE 6-1: kWh Usage by Family-type

	Total Population[5]		All-Electric[6]		Basic		
	No. Customers	Avg. kWh/ Customer	No. Customers	Avg. kWh/ Customer	No. Customers	Avg. kWh/ Customer	All Electric > Basic
Single Family	2545041	671	89920	801	2455121	666	20%
Multi-Family	1677537	397	367658	431	1309879	387	11%
Total Multi/Single Usage	4222578	562	457578	504 53.8%	3765000	569 58.1%	-11%

SCE asserted that the average size of single-family completed in 2013 is more than double that of the average of multi-family dwelling.[7] However, this statement is based on data for the western region for new houses built in a single year. In contrast, a report prepared by the CEC and KEMA illustrates a different portrait, as it shows that the average single-family dwelling size is about 1.6 to 1.8 times of that of the single family, as shown in the table below.[8]

[5] Exh. SCE-04, p.29, Table III-11.

[6] Exh. SCE-04, p.29, Table III-11.

[7] Exh. SCE-04, p.28, lines 10-13.

[8] CEC, 2009 CA Residential Appliance Saturation Study, October 2010, p.45.

Table ES-8: Comparison of Results by Surveying Method and Dwelling Type

	Single Family		Multi-Family (2-4 Units)		Multi-Family (5+ Units)		Mobile Homes	
	Initial Mail	Non-Response	Initial Mail	Non-Response	Initial Mail	Non-Response	Initial Mail	Non-Response
Completed Surveys	13,968	1,389	3,599	412	3,758	480	816	42
Weighted to Population	2,716,013	4,333,328	562,229	1,243,344	589,620	1,443,735	103,337	102,191
Average Electric Consumption	7,568	7,628	4,249	4,146	3,577	3,763	5,563	5,597
Average Gas Consumption	427	418	240	236	155	147	334	345
Average Dwelling Size	1,911	1,864	1,203	1,131	954.84515	927.2109	1,277	1,353
Average Dwelling Age	37.8	37.0	34.6	34.6	31.9	32.0	28.1	28.2
Average Number of People	2.82	3.39	2.54	2.79	2.09	2.43	2.13	2.63
Average Number of Seniors	0.61	0.35	0.42	0.21	0.40	0.20	0.79	0.37
Average Income	79,062	80,001	58,253	56,341	50,859	55,686	32,970	46,373
Owners	91%	86%	49%	33%	28%	22%	86%	84%
Central Cooling	59%	60%	46%	41%	43%	42%	70%	73%
Gas Space Heating	83%	86%	77%	74%	60%	62%	62%	51%
All Exterior Walls Insulated	57%	56%	45%	41%	43%	45%	60%	53%
CFL Penetration	87%	84%	85%	83%	84%	80%	88%	74%
Primary Language English	91%	84%	82%	74%	85%	76%	94%	95%
Head of Household Hispanic	17%	27%	23%	32%	18%	26%	11%	17%
College Grad or Higher	56%	54%	50%	47%	53%	52%	22%	20%

Source: *2010 California Residential Appliance Saturation Survey*

Furthermore, increasing the baseline quantity to large single family residences is not consistent with the California's overall energy conservation policy goals.

2. <u>Low Usage Residential Customers are Facing Significant Bill Impact Changes Due to the RROIR</u>

ORA illustrative rates filed in the RROIR for year 2016 are shown in Table 6-2 below. Using these rates, the bill impacts for all-electric multi-families caused by SCE's proposed increase to the baseline allowances in this GRC are shown in Table 6-3.

TABLE 6-2: ORA 2016 Illustrative Rates Presented in RROIR

		ORA PROPOSAL 2016 RATE
D	TIER 1	0.16600
	TIER 2	0.24200
	TIER 3	0.24200
	TIER 4	0.31000
	TIER 5	0.31000
	SVC FEES	0.94
D-CARE	TIER 1	0.10700
	TIER 2	0.16900
	TIER 3	0.16900
	TIER 4	0.22900
	TIER 5	0.22900
	SVC FEES	0.73

TABLE 6-3: All-Electric Multi-family Bill Impact

kWh Usage	No. Customer	% Customer	Monthly kWh	% Bill Impact	$ Bill Change
0 -50	2,219	0.8%	21	0.0%	
50 - 100	4,974	1.8%	82	0.1%	$0.0
100 - 150	11,841	4.3%	127	0.1%	$0.0
150 - 200	19,571	7.1%	177	0.2%	$0.0
200 - 250	24,309	8.8%	227	0.6%	$0.1
250 - 300	26,324	9.6%	275	1.4%	$0.2
300 - 350	26,197	9.5%	323	2.3%	$0.6
350 - 400	25,003	9.1%	373	3.3%	$1.2
400 - 450	22,635	8.2%	427	4.1%	$1.9
450 - 500	20,162	7.3%	474	4.7%	$2.8
500 - 550	17,133	6.2%	527	5.2%	$3.7
550 - 600	14,390	5.2%	577	5.5%	$4.5
600 - 650	11,811	4.3%	626	5.6%	$5.3
650 - 700	9,855	3.6%	668	5.7%	$6.0
700 - 750	7,801	2.8%	728	5.9%	$6.7
750 - 800	6,357	2.3%	779	6.0%	$7.6
800 - 850	5,075	1.8%	820	6.0%	$8.5
850 - 900	3,906	1.4%	883	6.1%	$9.1
900 - 950	3,121	1.1%	888	6.1%	$10.1
950 - 100	2,437	0.9%	970	6.2%	$10.2
1000 - 11	3,457	1.3%	1,013	6.0%	$11.5
1100 - 12	2,092	0.8%	1,143	5.9%	$11.9
1200 - 13	1,434	0.5%	1,234	5.8%	$13.6
1300 - 14	898	0.3%	1,327	5.9%	$14.6
1400 - 15	648	0.2%	1,452	5.6%	$16.5
1500 - 20	1,287	0.5%	1,670	5.5%	$17.4
2000 - 25	332	0.1%	2,135	4.7%	$20.4
> 2500	239	0.1%	3,470	2.7%	$23.8

The cumulative effects of the various structural and rate changes anticipated to be imposed on the residential class are not trivial, and must be considered as a complete package that will effect customer bills. Though the bill impacts of SCE's GRC all-electric baseline proposal appear moderate in isolation, concurrent rate change impacts from the RROIR should be considered. It should be noted that there have been many residential rate changes and more on their way. In the RROIR, SCE proposes to quickly reduce the number of tiers, flatten tier differentials, increase customer charges, and reduce baseline allowances from 53 percent to 50 percent of average usage. As part of the RROIR rate reform, lower tier usage customers already have seen significant rate increases during the last twelve months, as shown in Table 6-4:

TABLE 6-4: SCE Residential Rates

	SCE Residential Rates		
	Jan. 2014	**Jan. 2015**	**% Change**
Non-CARE			
Tier 1 (100% BL)	13.2	14.9	13%
Tier 2 (101-130% BL)	16.5	19.3	17%
Tier 3 (131-200% BL)	27.4	25.6	-7%
Tier 4 (>200% BL)	30.4	31.1	2%
Basic Charge - SF ($/month)	0.94	0.94	0%
Basic Charge - MF ($/month)	0.73	0.73	0%
CARE			
Tier 1 (100% BL)	8.8	9.7	10%
Tier 2 (101-130% BL)	11.0	12.5	14%
Tier 3 (131-200% BL)	20.0	19.9	-1%
Tier 4 (>200% BL)	20.0	19.9	-1%
Basic Charge - SF ($/month)	0.73	0.73	0%
Basic Charge - MF ($/month)	0.55	0.55	0%

Furthermore, additional changes are expected to come over the next three years. In Table 6-5, ORA calculated the bill impacts based on SCE's proposed OIR changes between July 2014 and 2018. Customers who consume at the baseline level will see substantial bill increases.

TABLE 6-5: Cumulative Bill Impacts Based on SCE RROIR Proposals

monthly	SCE	
kWh usage	2015-2018[9] cumulative	Avg Cum $ [10] Increase
Below 50	260.2%	$9.64
50 to 100	99.1%	$12.69
100 to 150	75.1%	$14.74
150 to 200	62.2%	$16.94
200 to 250	54.5%	$19.06
250 to 300	49.5%	$21.17
300 to 350	43.1%	$22.46
350 to 400	37.6%	$23.51
400 to 450	32.9%	$23.85
450 to 500	26.0%	$22.35
500 to 550	23.2%	$22.32
550 to 600	18.8%	$20.67
600 to 650	14.4%	$17.87
650 to 700	9.6%	$13.53
700 to 750	7.8%	$11.96
750 to 800	5.7%	$9.53
800 to 850	2.7%	$4.90
850 to 900	0.3%	$0.53
900 to 950	1.5%	$3.10
950 to 1000	-2.8%	-$6.47
1000 to 1100	-3.5%	-$8.66
1100 to 1200	-6.5%	-$18.48
1200 to 1300	-7.9%	-$24.63
1300 to 1400	-10.0%	-$34.43
1400 to 1500	-10.5%	-$38.70
1500 to 2000	-13.7%	-$61.95
2000 to 2500	-17.5%	-$106.01
> 2500	-22.8%	-$354.84

SCE's proposed baseline changes for all electric customers will be incremental to these changes. They will unnecessarily add more burden to the all-electric multi-family customers, who represent 80% of the overall all-electric

[9] ORA calculated bills based on July 2014 rates and proposed 2018 rates. This column shows the percentage increase in bills between these periods for different usage range.

[10] This column shows the average monthly dollar change in bills between summer 2014 and proposed 2018 bills.

use families, as SCE pointed out.[11] Based on all the reasons stated above, the Commission should reject SCE's propose to establish separate baseline allowances for all-electric customers living in single family homes versus multi-family homes at this time.

B. Coordination among Cases

The Commission also should direct SCE to consolidate its rate changes from various proceedings as much as possible, especially the ones that will occur in the same quarter. This will avoid frequent rate changes and unnecessarily swings in rates, both up and down. Rate changes will reflect the cumulative effect of changes from proceedings that have been resolved or are being resolved. There are at least three such proceedings: SCE's 2014 RDW, the RROIR, and the marginal cost and revenue allocation changes in this GRC. In addition, there are revenue requirements changes from a number of proceedings throughout the year.

A joint settlement agreement in SCE's 2014 RDW (supported by SCE, ORA, TURN, and a number other parties) has been adopted by the Commission. This agreement resolves various optional TOU and existing TOU rate issues, and adopts rates for schedules TOU-D-T, TOU-D, and TOU-EV. Therefore, issues about how to design TOU rate schedules are resolved, but the actual rates in those schedules will be impacted by issues pending in the RROIR as well as by various revenue requirements changes.

For the current tiered residential rates, ORA agrees with SCE that tiered rate reform, which includes reducing the number of tiers, reducing the tier rate differentials, and increasing fixed charges, are to be resolved in the RROIR. These issues are highly contested and an extensive record has been built in the RROIR. Therefore, ORA is not presenting testimony on those issues here. In the RROIR, SCE also proposed to reduce its baseline allowances from 53 percent to 50 percent of average usage. In the RROIR, ORA opposes SCE's

[11] Exh. SCE-04, p.27, lines 18-19.

recommendation and instead proposes to maintain the current allowance of 53 percent. ORA is concerned that a decrease in baseline allowances would lead even more bill increases for low-usage customers who are likely to shoulder more of the bill impact from the other tier rate reforms.

Moreover, setting baseline allowances at the bottom of the allowable range could result in baseline allowances becoming out of compliance if baseline allowances are not updated every year. ORA concurs with SCE that this issue is pending in the RROIR and does not need to be addressed in this GRC.

Finally, marginal cost and revenues allocation changes that are pending in this GRC will impact the final rates. These changes are incremental to the RROIR rate reform proposals and various revenue requirements changes that are unknown at this time. When SCE is implementing the GRC rates, it should allow parties ample time to review how these combined changes are developed. SCE should file a Tier 2 advice letter with complete workpapers when the AL is filed. The AL should clearly explain how it implements the decision(s) and provide the source documents for the actual revenue changes.

The Commission also should direct SCE to consolidate its rate changes from these various proceedings as much as possible, especially the ones that will occur in the same quarter. This will avoid frequent rate changes and unnecessarily swings in rates, both up and down. SCE should be required to show rates and revenue requirements change over a twelve month period in each of its rate AL filings. For example, when SCE files an AL to reflect revenue requirement and associated rate changes later in 2015, to set January 1, 2016 rates, it should provide non-CARE, CARE tiered rates, and the residential average rate ("RAR") and system average rate ("SAR") percent changes relative to the January 1, 2015 rates, to help parties to review the rate proposals more efficiently.

A common template for such rate filings should be used. ORA includes SDG&E's RROIR filing below as a sample to show how such rate changes can be presented.

ATTACHMENT A
RESIDENTIAL - ILLUSTRATIVE RATES
SAN DIEGO GAS AND ELECTRIC COMPANY
OCTOBER 17th REBUTTAL FILING RULEMAKING 12-06-013 PHASE 1

Revenue Requirement ($Millions)

	Nov-13	Dec-13	Jan-14	Feb-14	Apr-14	May-14	Aug-14[1]	No Revenues				2.1% CPI			
								2015	2016	2017	2018	2015	2016	2017	2018
SDG&E Total System[3]	3,458	3,575	3,545	3,545	3,741	3,732	3,758	3,758	3,758	3,758	3,758	3,834	3,911	3,991	4,072
Residential Class[3]	1,611	1,661	1,648	1,648	1,702	1,612	1,591	1,591	1,591	1,591	1,591	1,626	1,663	1,700	1,738

Total Rates - Schedule DR and DR-LI - with SDG&E Proposal* - Proposed Baseline

Non-CARE	Nov-13	Dec-13	Jan-14	Feb-14	Apr-14	May-14	Aug-14[1]	No Revenues[2]				2.1% CPI[2]			
								2015	2016	2017	2018	2015	2016	2017	2018
Monthly Service Fee ($/Month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	7.50	10.00	10.21	5.00	7.50	10.00	10.21
Summer Energy Rates (cents/kWh)															
Tier 1	14.8	14.8	15.0	15.4	15.4	15.4	16.5	18.9	19.4	19.6	20.3	19.8	20.3	21.0	22.2
Tier 2	17.1	17.1	17.3	17.8	17.8	17.8	18.9	18.9	19.4	19.6	20.3	19.8	20.3	21.0	22.2
Tier 3	34.6	36.6	35.8	34.9	37.1	35.7	36.9	29.4	27.2	25.5	24.3	29.3	28.4	27.3	26.7
Tier 4	36.6	38.6	37.8	36.9	39.1	37.7	38.9	29.4	27.2	25.5	24.3	29.3	28.4	27.3	26.7
Winter Energy Rates (cents/kWh)															
Tier 1	14.8	14.8	15.0	15.4	15.4	15.4	16.5	16.6	16.9	16.9	17.3	17.3	17.7	18.1	19.0
Tier 2	17.1	17.1	17.3	17.8	17.8	17.8	18.9	16.6	16.9	16.9	17.3	17.3	17.7	18.1	19.0
Tier 3	32.7	34.8	33.9	33.0	35.2	32.2	33.4	25.9	23.6	22.0	20.8	25.7	24.7	23.6	22.8
Tier 4	34.7	36.8	35.9	35.0	37.2	34.2	35.4	25.9	23.6	22.0	20.8	25.7	24.7	23.6	22.8
Minimum Bill ($/Day)	0.170	0.170	0.170	0.170	0.170	0.170	0.170	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CARE															
Monthly Service Fee ($/Month)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.50	3.75	5.00	5.11	2.50	3.75	5.00	5.11
Summer Energy Rates (cents/kWh)															
Tier 1	9.9	9.9	10.0	10.3	10.3	10.0	10.5	11.7	12.6	13.3	13.8	12.3	13.1	14.2	15.0
Tier 2	11.6	11.6	11.6	12.0	12.0	11.7	12.3	11.7	12.6	13.3	13.8	12.3	13.1	14.2	15.0
Tier 3	17.5	17.5	17.6	17.6	17.6	17.3	18.7	18.7	18.0	17.5	16.7	18.6	18.8	18.7	18.2
Tier 4	17.5	17.5	17.6	17.6	17.6	17.3	18.7	18.7	18.0	17.5	16.7	18.6	18.8	18.7	18.2
Winter Energy Rates (cents/kWh)															
Tier 1	9.9	9.9	9.9	10.3	10.3	10.0	10.5	10.2	10.8	11.3	11.6	10.6	11.3	12.1	12.7
Tier 2	11.6	11.6	11.6	12.0	12.0	11.7	12.3	10.2	10.8	11.3	11.6	10.6	11.3	12.1	12.7
Tier 3	16.4	16.4	16.4	16.4	16.4	16.2	17.4	16.4	15.5	15.0	14.1	16.2	16.2	16.0	15.5
Tier 4	16.4	16.4	16.4	16.4	16.4	16.2	17.4	16.4	15.5	15.0	14.1	16.2	16.2	16.0	15.5
Minimum Bill ($/Day)	0.136	0.136	0.136	0.136	0.136	0.136	0.136	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CARE Effective Discount	39%	40%	40%	39%	41%	41%	41%	38%	36%	34%	34%	38%	36%	34%	34%

**SDG&E's proposal is reflected beginning "No Revenues - 2015"*

Class Average Rates (cents/kWh)

	Nov-13	Dec-13	Jan-14	Feb-14	Apr-14	May-14	Aug-14[1]	No Revenues				2.1% CPI			
								2015	2016	2017	2018	2015	2016	2017	2018
Residential Class Average Rate[3]	20.6	21.2	21.1	21.1	21.8	21.2	21.4	21.4	21.4	21.4	21.4	21.9	22.4	22.9	23.4
System Average Rate[3]	17.8	18.4	18.1	18.1	19.3	19.1	20.5	20.5	20.5	20.5	20.5	20.9	21.3	21.7	22.2

[1] August 1, 2014 Rates adjusted for 2015 test year sales.
[2] Rates reflects the first four years of the 5 year transition plan of SDG&E's baseline proposal
[3] Presentation of Residential and System Class Average Rates and Revenues exclude California Climate Credit Revenues
Note: Schedule DR and DR-LI are SDG&E's standard rate schedules for residential non-CARE and CARE service

Key	
November 2013	Reflects rates effective November 1, 2013 pursuant to AL 2513-E.
December 2013	Reflects rates effective December 1, 2013 pursuant to AL 2544-E.
January 2014	Reflects rates effective January 1, 2014 pursuant to AL 2564-E.
February 2014	Reflects rates effective February 1, 2014 pursuant to AL 2568-E.
April 2014	Reflects rates effective February 1, 2014 pursuant to AL 2568-E.
May 2014	Reflects rates effective May 1, 2014 pursuant to AL 2595-E
August 1, 2014 Rates	Reflects rates pursuant to 2632-E. Note, AL 2617-E reflects compliance filing for implementation of Decision ("D.") 14-06-029, approved by the Commission on June 12, 2014, Settlement Agreement for Phase 2 Interim Residential Rate Design Changes for SDG&E.
No Revenues	No change from rate revenues for August 1, 2014 rates beginning 2015 reflecting 2015 test year sales.
2.1% CPI	Reflects a 2.1% CPI adjustment to August 1, 2014 revenues beginning in 2015 reflecting 2015 test year sales.

The following table summarizes the various SCE residential rate schedules and where they are addressed in various proceedings.

TABLE 6-6: SCE'S RESIDENTIAL RATE SCHEDULES

Schedule	Brief description	Status
D	Current residential default rate, 4-tiered. Expect to become 3 tiers in 2015, and potentially become 2 tiers in 2018.	To be resolved in R.12-06-013. Main disputes: 1) customer charge, 2) tier structure & tier ratios. This GRC2 will add another layer of impact due to marginal cost, cost allocation changes, and SCE's all-electric baseline proposal.
D-CARE	Comparable to D schedule but for qualified low income customers.	Same as D and effective CARE discount rate.
DM	Master-metered, multi-family (residential hotels, recreational vehicle parks), closed to new customers on June 13, 1978	Main issue is the master meter discount, which is to be resolved in this case but it should be updated based on the RROIR adopted rate designs.[12]
DMS-1	Multi-family, sub-metered or master-metered accommodations, closed to new on Dec. 1981.	Same as above.
DMS-2	Multi-family, sub-metered or master-metered mobile parks, closed to new on Jan. 1997.	Same as above.
DMS-3	RV Park accommodations with separately sub-metered units.	Same as above.
DS	Seasonally differentiated rates	Will be migrating to TOU rate options per 2012 GRC.
TOU-D-T	Seasonal & time-differentiated 2-tiered energy charges	Resolved in the 2014 RDW
TOU-D	Simplified non-tiered TOU rate with two options: (1) $16/month customer charge and no baseline credit (TOU-D-A), and (2) The current customer charge and a baseline credit (TOU-D-B). Schedule TOU-D-A is subject to a 5% enrollment cap.	Resolved in the 2014 RDW
TOU-EV-1 & 2	Separately metered EV charging or whole-house EV	Resolved in the 2014 RDW
D-SDP	Summer discount plan	Retain current incentive, update in next Demand Response program proceeding.[13]

[12] ORA's marginal customer costs using a rental method would result in the same marginal customer costs as those proposed by SCE in the GRC2. Therefore, ORA is not revising SCE's master meter discounts based on its GRC2 proposal. ORA also agrees that these discounts should be updated based on the exact rate structure adopted by the Commission in the RROIR.

[13] ORA concurs with SCE that this be addressed in the demand response program proceeding.

IV. CONCLUSION

As explained above, the main issue in this GRC is about SCE's proposal to apply different baseline allowances to all-electric single and multi-family dwellings. ORA recommends that the Commission reject this proposal due to the fact that many low-usage customers are facing significant bill increases from the RROIR rate reform changes. ORA concurs with SCE that most of the other residential rate issues are pending before the Commission in the RROIR, and that TOU rate design has been resolved in the latest RDW.

CHAPTER 7

SMALL COMERICAL RATE DESIGN

PETER MORSE

TABLE OF CONTENTS

CHAPTER 7
SMALL COMERICAL RATE DESIGN
PETER MORSE

I. SUMMARY AND RECOMMENDATIONS

This Chapter analyzes Southern California Edison's ("SCE") rate design proposals for its nearly half a million small commercial customers and presents the Office of Ratepayer Advocates' ("ORA's") recommendations. SCE's Small Commercial customers recently completed a transition to default TOU rates, with approximately half transitioning in January/February 2014 and remainder in January/February 2015.

D.13-03-031 requires that these customers be moved to Critical Peak Pricing ("CPP") rates on January 1, 2016.[1] SCE proposes to delay this transition date to April 1, 2017, and to move all eligible accounts together on this date. They would be placed on "CPP lite" rates where CPP event charges and credits would be set at one half of the full marginal capacity cost that would otherwise apply. In addition, SCE proposes a 5.6% reduction in its monthly customer charges.

ORA agrees with SCE's proposed delay in the transition date and with placing all customers on CPP lite. ORA also agrees with SCE's proposed decrease in the customer charge. With the introduction of CPP lite, customer marketing, education and outreach will be important. More specifically, ORA proposes the following, intended for application to small commercial customers only:

- Transition customers to default "CPP lite" rates no earlier than April, 1 2017.
- Require SCE to provide customers with enhanced, measurable, goal oriented outreach and education as Ordered for PG&E in D. 10-02-032, Ordering Paragraphs 12-16, for the transition to "CPP lite" rates.

[1] D.13-03-031, Ordering Paragraphs 5 & 7.

- Implement new “snap credits” under which portions of particularly high summer bills incurred due to new dynamic rates could be deferred to be repaid over three to six months
- As proposed by SCE, provide one year of bill protection to customers defaulting to or opting into CPP rates.

II. APPLICANT’S PROPOSALS

In its application, SCE proposes to:

- Transition all applicable customers to default CPP rates on April, 1 2017, a date that ensures that all customers have at least two years of TOU data for the summers, and that SCE will have adequate time to communicate rate impacts of the CPP migration sufficiently in advance of summer but not during the busy holiday season.
- Default all eligible small and medium commercial and industrial (“C&I”) customers to the “CPP-Lite” rate option, in which case, the CPP price adder is half of the full value of generation capacity.
- Default all eligible small C&I customers to the CPP-Lite rate option within Schedule TOU-GS-1, with the option for customers to opt-out to TOU rates.
- Provide one year of bill protection to customers defaulted to (and opting into) CPP, and make any bill protection-related refunds available to customers following the next scheduled meter read date (for customers who opt out of CPP) rather than at the end of the first year on CPP.
- Reduce the customer charge from $25.43 to $24.00 per month, or a 5.6% reduction.

III. DISCUSSION & ORA’S PROPOSALS

A. Marketing Education and Outreach Be Required as Ordered for PG&E in D. 10-02-032, for Implantation of CPP Rates

A key to smoothly transitioning customers to CPP rates is ensuring effective marketing, education and outreach (“ME&O”). In the past, ORA has recommended objective measures of ME&O. SCE states in direct testimony:

> SCE also requested funding necessary to implement and execute ME&O activities in A.13-11-033. Please

> refer to SCE's prepared testimony for a detailed discussion of ME&O activities for the CPP transition.[2]

The application cited is SCE's Test Year ("TY") 2015 GRC Phase I. The testimony referenced therein includes less than two pages, focused around ensuring that SCE has accurate customer information so that customers can be contacted prior to CPP events.[3] SCE's GRC Phase I includes a request in the TY 2015 of $850,000.

> In order to support the implementation of Dynamic Pricing as described above, SCE forecasts an incremental $825,000 in the Test Year.[4]

In response to ORA discovery, SCE further outlined its intended ME&O plan for the implementation of CPP rates. SCE's ME&O plan focuses on "general market communications," "direct communications," "stakeholder outreach and engagement" and "employee ambassador effort" in a multi-phased approach.[5] SCE has not provided information on how such efforts related to dynamic pricing will be coordinated with similar outreach efforts approved through other proceedings, such as demand response, energy efficiency, and other demand-side management and related services, as directed in D. 12-04-045.[6]

There also are several important approaches to ME&O adopted in D. 10-02-032, which implemented PG&E's non-residential peak-day pricing program, that are not included in SCE's implementation plan for the proposed April 1, 2017 "CPP lite" rate transition. ORA recommends to Commission adopt the same rules as D.10-02-032, for SCE (below are some highlights from D. 10-02-032 on ME&O, see Appendix A for full list of rules):[7]

---

[2] Ex. SCE-4, p. 47, also see A.13-11-033, SCE-04, Volume 3, pp. 74-75.

[3] See Appendix B.

[4] See A. 13-11-003, Ex. SCE-4, Vol. 3, p. 75.

[5] SCE's response to ORA-PM1-008, Q. 9.

[6] See D. 12-04-045, p. 77.

[7] For highlights aspects of ME&O adopted in D. 10-02-032, with sight modifications, see Appendix A for Ordering Paragraphs 12-16 on ME&O.

- Provide an opportunity for the Commission's Business & Community Outreach group to provide input on ME&O efforts.
- Collaboratively develop with customers educational goals that SCE must achieve by the time it reaches its default date.
- Design the methods that will be used to directly educate the 10% of small commercial customers whose bills are likely to be increased by the largest percentage based on previous year's usage.
- File a Tier 3 advice letter within 120 days of this final decision clearly identifying and describing the specific performance measurements, which SCE will use to determine that its outreach and education campaign is successful.
    - Possible examples of measurements could include, but should not be limited to, quantifying benchmarks of successful outreach efforts such as: number of workshops held, minimum participants attended, number of customers signed up for "My Account," number of customers that respond to the utility indicating they will remain on or opt out of CPP, the number of customers calls or complaints after a Peak Day Pricing event, and the number of customers educated about demand response and energy efficiency opportunities.
    - SCE should also include a detailed plan with a timeline to develop customer surveys. The plan should include a description of the information the utility will gather from customers through survey questions to measure the success of its outreach.
- Prepare a monthly report to be provided to the Energy Division and posted on a public website. This monthly report shall include a breakdown of cost categories and money spent on education and outreach as well as a narrative description that describes the costs. SCE shall work with the Energy Division to design an appropriate format for the reports. Reports should be filed until one year after customers transition to CPP rates.
- A description of how customers will be educated about the tools and programs available to enable them to reduce energy consumption when a peak event is called, including energy efficiency and distributed generation and storage (effort should be made to coordinate this approach with other integrated marketing approaches).

In D. 12-04-045, the Commission approved funding for SCE's CPP customer outreach and education for 2012-2014, stating:

> Therefore, we make an exception to our cost-effectiveness criteria by approving SCE's request of $7.49 million for its Critical Peak Pricing program (customers with demand less than 200kW).[8]

ORA is concerned that SCE will drastically underspend approved funding for ME&O, leading to the necessity for further orders like D. 10-02-032. Table 7-1 below provides an example of how SCE has underspent Commission approved funding on Demand Response programs.

TABLE 7-1: AUTHORIZED BUDGETS IN D. 09-08-027 TO THE PERCENT SPENT ON ME&O AND DECISION ADOPTING DEMAND RESPONSE ACTIVITIES AND BUDGET FOR 2012 THROUGH 2014

Utility[9]	Total Approved Funds Local DR ME&O 2009-2011	Percent Spent from 8/09-11/11	Total Requested Funds allocated toward Local DR ME&O 2012-2014	Total Approved Funds for Local DR ME&O 2012-2014
SCE	$9,381,464	34.9%	$40,780,659	$ 22,000,000[10]

D. 12-04-045 also stated the following specific to SCE's requested funding for ME&O to customers transitioning to CPP rates:

> PG&E was the first utility to request funding for Critical Peak Pricing marketing to small commercial customers in its 2009 Rate Design Window. The Commission approved PG&E's request, but required that the utility fulfill reporting requirements to ensure that the expenses for the effort were transparent and that outreach and education efforts were effective. The Commission authorizes SCE marketing request here, and direct the utility to work with Commission staff to develop timelines for the same reporting requirements

[8] D. 12-04-045, p. 138.

[9] D. 12-04-045, p. 85.

[10] D. 12-04-045, approved Critical Peak Pricing > 200 kW of $275,000, Critical Peak Pricing <200kW of $5,500,000 and DR ME&O of $1,000,000, see D. 12-04-045, pp. 93-94.

> that are required of PG&E for its Critical Peak Pricing outreach[11] to small commercial customers.[12]

In SCE's "TIME-OF-USE OUTREACH UPDATE" dated January 28, 2014,[13] 34% of GS-1 customers were aware of TOU rates, compared to 51% of GS-2 and 61% of PA-1/2 customers, respectively. The data confirms that GS-1 customers require greater outreach for the default to CPP rates than conducted prior to default TOU rates.

ORA recommends that the Commission adopt the same rules as ordered for PG&E in D. 10-02-032, and reiterated in D. 12-04-045, to ensure a more goal oriented, measurable and comprehensive ME&O program to ensure an effective transition for small commercial customers to CPP rates.

B. Transition of Small Commercial (GS-1) Customers to Default CPP Rates

Small commercial (GS-1) customers are a very diverse group, and effectively implementing new rates will take considerable outreach and education. Eligible customers were defaulted to TOU rates in early 2014 or 2015, and D.13-03-031 directed SCE to begin implementing CPP rates January 1, 2016. Absent of any change in the directives in D. 13-03-031, SCE would implement CPP rates starting in 2016 and continuing into 2017.

ORA agrees with SCE that single rather than a three-stage CPP rate transition date on January 1, 2017 would allow a more streamlined and more efficient outreach and education effort.

SCE also states:

> …SCE will realize administrative efficiencies by reducing the implementation waves from three to one, customers will be easier to reach and more receptive to outreach if their opt-out window does not conflict with the holiday season, and the default process will

[11] D.10-02-032, OP 13-16.

[12] D. 12-04-045, p. 87.

[13] See Appendix C.

> conclude close to the same time envisioned by D.13-03-031.[14]

With a single transition date, SCE can mass-market the same message to its entire small commercial customer class or to specific small business publications, include bill inserts, and partner with trade and business organizations. Customers will benefit if there is a clear, predictable, and expected rollout schedule, and a message that can be clearly communicated.

C. "CPP Lite" for Small Commercial (GS-1) Customers

The ORA agrees with SCE for taking the common-sense approach of proposing "CPP-Lite" rates for small commercial customers. Implementing the "CPP-Lite" for customers who are not familiar or have the interest in understanding CPP rates will reduce customer complaints and mitigate against summer and winter bill fluctuations.

SCE states:

> Continuing the use of the 2012 GRC settlement structure provides a measure of rate stability that will greatly help with customer acceptance and understanding of time variant rates.[15]

> CPP-Lite and CPP with a CRL were implemented with an effective date of April 1, 2013 with the approval via staff letter of Advice Letter (AL) 2872-E, 2872-E-A, 2872-E-B, and 2872-E-C.[16]

The settlement of A. 11-06-007 states:

> CPP-Lite will be available as an option for all GS-1 customers. CPP at the full cost-based level will remain available to customers already served on CPP but will be closed to new customers.

ORA cautions that small businesses will likely have even more difficulty adapting to dynamic pricing than large ones, and will be less equipped to deal with

[14] Ex. SCE-4, p. 38.

[15] Ex. SCE-4, p. 51.

[16] Ex. SCE-4, p. 46. See footnote 46.

the bill volatility associated with dynamic rates. SCE's C&I customers with demands greater than or equal to 200 kW experienced a much more gradual transition to CPP since not all had Smart Connect meters or the required one year of Smart Connect billing data, and large customers took service on mandatory TOU rates for many years prior to being subject to default CPP rates. ORA recommends the Commission adopt SCE's proposal to default eligible small commercial customers to the "CPP-Lite" rate.

D. Bill Protection for Default CPP Rate

Consistent with the 2012 GRC settlement structure for customers optioning into CPP rates, SCE proposes one year of bill protection to customers defaulted to (and opting into) CPP, and making any bill protection-related refunds available to customers following the next scheduled meter read date, rather than at the end of the first year on CPP. Under SCE's proposal, if a customer opts out of CPP, they could obtain the bill protection funds in about a month, rather than at the end of the year. ORA agrees with SCE's proposal for bill protection.

E. ORA Recommends the Commission adopt Snap Credits for Customers Transitioning to CPP Rates

ORA recommends SCE implement "snap credits." This would be a program that would allow portions of particularly high summer bills, incurred due to new dynamic rates, to be deferred and repaid over three to six months. Allowing customers "snap credits" will mitigate late payments, and "rate shock." Snap credits were adopted for San Diego Gas and Electric ("SDG&E") in D. 12-12-004.[17] ORA urges the Commission to afford the same option to SCE's small commercial customers defaulting to CPP rates.

Snap credits also may be helpful for customers who have signed up for SCE's Level Pay Plan ("LPP") program. Under this program, participating residential and small commercial customers pay a flat bill for eleven months with a true-up in the twelfth month to account for the difference between their actual

[17] D. 12-12-004, OP 7.

and levelized bills over the year. SCE proposes to continue this program for residential and small commercial bundled-service customers.[18] ORA agrees with the continuation of the LPP program for eligible small commercial customers. But it is concerned that the new CPP rates may adversely affect a customer's ability to pay the difference between their actual and levelized bills over the year if the CPP implementation date falls in the middle of the 12-month period designated in a customer's LPP. Thus allowing customers on LPP to also receive snap credits may help then in the first year of CPP.

F. Customer Charge

SCE proposes a reduction in the customer charge from $25.43 (April 1, 2014) to $24.00 per month, or a 5.6% reduction. The small reduction brings the divergence of small commercial single-phase customer charges between California's three largest investor owned utilities slightly closer. Customers who remain on the most utilized TOU rate (option A) without demand charges will experience bill decreases under SCE's proposals.[19] ORA supports SCE's proposal. ORA will address intervener testimony as needed and participate in settlement negotiations.

IV. CONCLUSIONS

ORA has been encouraged by many of the points in SCE's small commercial rate design proposals, most notably, that eligible small business customers be defaulted to "CPP-Lite" rates on a single date in 2017. However, ORA is concerned with customers transitioning to CPP rates, and supports a more robust ME&O plan with clear performance metrics. ORA will continue to participate in the proceeding concerning small commercial customers and address intervener testimony as needed.

---

[18] Ex. SCE-4, p. 22.

[19] See SCE's response to ORA-PM1-008, Q. 2, Attachment.

APPENDIX A

Decision 10-02-032, February 25, 2010

Decision on Peak Day Pricing for Pacific Gas and Electric Company

ALJ/DKF/jt2 **Date of Issuance 3/2/2010**

Decision 10-02-032 February 25, 2010

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Approval of its 2009 Rate Design Window Proposals for Dynamic Pricing and Recovery of Incremental Expenditures Required for Implementation (U39E).	Application 09-02-022 (Filed February 27, 2009; amended March 13, 2009)

DECISION ON PEAK DAY PRICING FOR PACIFIC GAS AND ELECTRIC COMPANY

10. Pacific Gas and Electric Company's Alternative 1 residential Peak Day Pricing proposal is adopted.

11. Regarding person-to-person outreach, Pacific Gas and Electric Company shall ensure that a customer service representative directly contacts at least the 10% of small and medium customers whose bills are likely to be increased by the largest percentage based on previous year's usage, if they are defaulted to and stay on the PDP rate. PG&E shall include a description of how utility representatives will engage theses customers in it Customer Education and Outreach plan.

12. Pacific Gas and Electric Company shall work with Energy Division and the Business & Community Outreach group and develop a written customer education and outreach plan. The utility shall post the plan to the service list within 60 days of the final decision. Pacific Gas and Electric Company shall provide parties to the proceeding the opportunity to provide comments and feedback on the plan. Pacific Gas and Electric Company must include the plan and may include revisions based on feedback from parties in the advice letter required in Ordering Paragraph 15. The plan shall be submitted with the advice letter for informational purposes only and the utility may begin implementing the plan prior to a resolution on the advice letter. The plan shall include:

- Education goals the utility expects to have achieved with customers by the time they reach their default date;
- A list of monthly timelines for activities, the types of activities that will be conducted (i.e., mailings, e-mails, calls, workshops, meetings with business or agricultural leaders or organizations), as well as the geographic area, customer groups, and market segments that will be targeted, including ethnic and traditionally "hard to reach" customers;

- The methods that will be used to directly educate the 10% of small and medium customers whose bills are likely to be increased by the largest percentage based on previous year's usage if they stay on the Peak Day Pricing rate;
- A description of how customers will be educated about the tools and programs available to enable them to reduce energy consumption when a peak event is called, including energy efficiency and distributed generation and storage (effort should be made to coordinate this approach with other integrated marketing approaches); and
- A summary of other outreach and education plans, models or strategies around the country that PG&E can incorporate into its proposal to increase the number of small and medium customers that experience person to person interactions.

The Director of the Energy Division may direct the utility to make additions to the plan if necessary.

13. Pacific Gas and Electric Company shall work with the Commission's Business & Community Outreach group to determine how the group can assist Pacific Gas and Electric Company in outreach efforts to small and medium customers.

14. Pacific Gas and Electric Company shall issue a request for proposals in 2011, in order to engage a third party to conduct an evaluation in 2012 of the effectiveness of customer education and outreach efforts of small and medium customers. Pacific Gas and Electric Company shall work with the Demand Response Evaluation and Measurement Committee, which will have input into the project design and scope of work for the request for proposals and also take part in scoring proposals and reviewing the final report.

15. Pacific Gas and Electric Company shall:

- File a Tier 3 advice letter within 120 days of this final decision clearly identifying and describing the specific performance measurements, for each of its customer classes, which it will use to determine that its outreach and education campaign is successful;

  - Possible examples of measurements could include, but should not be limited to, quantifying benchmarks of successful outreach efforts such as: number of workshops held, minimum participants attended, number of customers signed up for "My Account," number of customers that respond to the utility indicating they will stay on or opt out of Peak Day Pricing, and maximum number of customers calls or complaints after a Peak Day Pricing event, and number of customers educated about demand response and energy efficiency opportunities;
  - Pacific Gas and Electric Company should also include a detailed plan with a timeline to develop customer surveys for each customer class. The plan should include a description of the information the utility will gather from customers through survey questions to measure the success of its outreach;

- Prepare a monthly report to be provided to the Energy Division and posted on a public website. This monthly report shall include a breakdown of cost categories and money spent on education and outreach as well as a narrative description that describes the costs. Pacific Gas and Electric Company shall work with the Energy Division to design an appropriate format for the reports. Reports should be filed until customer outreach and education activities approved in this decision and the 2011 general rate case are completed;
- Provide a semi-annual written report to all parties on the service list, which includes foundational research conducted and findings, all outreach activities that have occurred, including number of customers that have received person to person contact, lessons learned from interactions, performance measurements that have or have not been met and if necessary modifications to outreach efforts going forward. The form and content of the report should be coordinated with the Energy Division and

should be modified as necessary on an ongoing basis. The first of these reports should be completed and served on all parties no later than June 1, 2010, and reports should continue until six months after customer outreach and education activities approved in this decision and in the 2011 general rate case are completed;

- Hold quarterly progress report presentations. Two of the meetings shall be with Energy Division, the Division of Ratepayer Advocates and the Business & Community Outreach group. Two of the meetings shall be in conjunction with the semi-annual written reports and open to all parties on the service list;

- Provide to the Commission's Business & Community Outreach group, Pacific Gas and Electric Company's schedule of outreach events, at which Pacific Gas and Electric Company staff will be educating customers about Peak Day Pricing and time-of-use rates. (Events include workshops, industry meetings, and meetings with members of Chambers of Commerce, or other industry or customer segments that may not be represented by Chambers of Commerce, etc.) To the extent possible, Pacific Gas and Electric Company should coordinate such events with the Business & Community Outreach group; and

- After each of the presentations to parties on the service list, provide an addendum to the semi-annual written report to parties on the service list. The addendum shall include a workshop report describing recommendations and issues raised and how Pacific Gas and Electric Company will proceed as a result of the discussions and recommendations.

16. The effectiveness of the utility's education and outreach efforts shall be a factor in approving requests for additional funding for customer education and outreach for Peak Day Pricing in future proceedings.

APPENDIX B

Southern California Edison's A. 13-11-003, Ex. SCE-04,
Vol. 3

Customer Service and Delivery of Information

Application No.: A. 13-11-003
Exhibit No.: SCE-04, Vol. 3
Witnesses: L. Cagnolatti
K. Devore
J. Lim
C. Prescott
T. Walker

SOUTHERN CALIFORNIA EDISON®

An *EDISON INTERNATIONAL®* Company

(U 338-E)

Customer Service
Volume 3 - Customer Service and Information Delivery

Before the

Public Utilities Commission of the State of California

Rosemead, California
November 2013

rates as adopted by the Commission in D.13-03-031 and address the continued growth and complexity in the administration of the NEM tariff.

(1) Implementation of Dynamic Pricing

During the preparation of SCE's 2012-2014 Demand Response Application, SCE expected that default CPP was going to be implemented in the 2012 timeframe. Funding to support this transition was requested in A.11-03-003 and approved in D.12-04-045. However, in D.13-03-031, the Commission revised the timeline for default CPP and instead ordered that small (GS-1) and medium (GS-2) non-residential service accounts be defaulted to CPP rates beginning on January 1, 2016. Therefore, minimal expenses were incurred for default CPP in the 2012 timeframe and the funding request to support the transition is being requested in this application.

SCE estimates that approximately 600,000 service accounts will be impacted by this default. This will be a significant transition for customers, and an extensive customer education and outreach plan is needed to effectively support this transition. In order to minimize the confusion around the new pricing plan and encourage behavioral change that helps customers benefit from the rate, customers must be aware that they are on a new rate, how the rate works, and what actions they can take to benefit from the rate/minimize its impact on them. To educate these impacted customers, SCE will communicate to this highly diverse group of customers in a simple understandable manner through a mix of channels and in multiple languages.

In 2015, prior to the default of these customers to CPP, SCE will communicate key information to customers, including their options. Pre-default communications will emphasize that the CPP program does include a full year of bill protection for the first year of participation. To encourage participation, SCE's communications will help them better understand the cost impacts to their future bills by including a customized rate analysis. This analysis is intended to reveal potential bill impacts arising from future CPP participation based on the customer's historical usage, along with information on how changes in usage behavior can help to maximize incentives.

Another objective of the pre-default communications will be to obtain current customer contact information for day-ahead event notification purposes. Because the CPP rate structure includes increased energy charges during a CPP event period, it is important that customers receive notification about the event in time to decide whether to make operational adjustments on the following event day.

SCE's program allows customers to enroll in event notification services, which lets them select a preferred contact number/method (text messaging, voicemail, or e-mail). If a customer does not provide a notification preference, SCE will rely on its existing telephone contact information stored in its Customer Service System. However, this information may not be accurate for large percentage of these customers. This is because customer contact information is collected at the time customers turn on electric service and is typically updated only if customers proactively contact SCE and/or if customers update the information when/if they access their personal online information on SCE's website. The contact information collected at the time of turn-on for many of the business accounts also may not be the appropriate contact to receive CPP event notifications. SCE anticipates that multiple communications may be required to collect the appropriate contact information. After the implementation, SCE plans to do follow-up communications to confirm rate changes and remind customers of the actions they must take to maximize the benefits of participation in the CPP program. Additionally, SCE will remind customers when their bill protection periods are about to end. Finally, throughout the transition, SCE plans to perform market research. Research objectives will include validating (1) program default messaging, (2) usefulness and understandability of rate analysis, and (3) preferred methods of communication.

Second, SCE requests funding necessary to implement and execute CPP event notification measures. In order to provide event notifications, SCE will leverage multiple communication channels including automated voicemail, text messaging, and e-mail to inform customers of CPP events on a day-ahead basis. Day-ahead notification of events is essential to provide customers with ample opportunity to plan for CPP events.

Finally, SCE plans to increase marketing of Real Time Pricing (RTP) rate. Prior to April 2013, RTP was available only for large non-residential customers with demands greater than 500 kW. Beginning in April 2013, the RTP rate is available to all non-residential customers.[27] SCE plans to increase its ME&O activities in order to develop customer awareness with the goal of making the RTP easier for all customer classes to understand and participate in effectively.

In order to support the implementation of Dynamic Pricing as described above, SCE forecasts an incremental $825,000 in the Test Year.

---

27 *See* D.13-03-031, Ordering Paragraph 3, Attachment C (Small Commercial and Industrial Customer Rate Design Settlement Agreement) p. 13; Ordering Paragraph 4, Attachment D (Medium and Large Commercial Customer Rate Design Settlement Agreement) p. 17.

APPENDIX C

Southern California Edison's Time-of-Use Outreach Update, Dated January 28, 2014

SOUTHERN CALIFORNIA EDISON
An EDISON INTERNATIONAL® Company

SCE TIME-OF-USE OUTREACH UPDATE

January 28, 2014

SCE PUBLIC

Metrics Summary

	Question	Wave 1 Total		Wave 2 Total		GS-1		GS-2		PA-1/2		Negative Impact	
	Sample Size (n)	904		902		443		385		74		86	
		Percent of Respondents											
1	Customers are aware of TOU rates	17%		39%		34%		51%		61%		57%	
2	Customers are aware of receiving information about solutions – new programs, services, or tools – that can help them manage energy use on Time-of-Use rates	23%		28%		28%		28%		33%		28%	
na	Customers are aware of the transition to TOU	9%		47%		42%		58%		68%		62%	
		Mean Scores / Top 5 Box (rated 6-10)											
4	Your company understands how its monthly bill would be impacted by participating on the Time-of-Use rate	6.0	36%	6.3	46%	6.3	44%	6.6	50%	6.4	48%	6.8	52%
5	Your company understands that it may need to manage its electricity use differently on the Time-of-Use rate	6.6	45%	6.4	47%	6.4	46%	6.4	50%	6.9	58%	6.4	57%
6	Your company understands that reducing peak demand will depend on your actions on very few specific days and times.	6.6	46%	6.5	50%	6.4	48%	6.9	55%	6.2	44%	6.3	48%
7	Your company understands that once the transition takes place, the Time-of-Use rate will be your new applicable rate and you can't opt-out of Time-of-Use	5.5	28%	5.9	40%	5.8	40%	6.1	40%	5.9	34%	5.8	44%
8	Information and tools from SCE helped you understand how your bill would be impacted by the TOU rate	5.2	28%	5.9	42%	5.9	41%	6.0	44%	5.5	40%	6.2	48%
9	There are peak hours during the day when demand for electricity is greatest and therefore the cost of providing electricity is more expensive	7.1	61%	7.1	61%	7.1	60%	7.2	62%	7.6	67%	7.1	63%
10	Your company understands where or how to get more information about rebates, energy efficiency programs, and tips from SCE that can help you lower your bill on the new rate	na		6.0	45%	6.0	44%	6.2	47%	5.9	44%	5.6	41%
11	Your company is aware of the rebates, energy efficiency programs, and tips offered by SCE that can help you manage your energy use on the new rate	na		5.2	34%	5.2	34%	5.3	34%	5.4	39%	5.1	33%

APPENDIX A

QUALIFICATIONS OF
ORA WITNESSES

List of ORA Witnesses and Respective Chapters

Chapter 1	Marginal Customer Cost	Dan Willis
Chapter 2	Marginal Distribution Demand Cost	Louis Irwin
Chapter 3	Marginal Energy Costs and LOLE Allocation Among TOU Periods	Bob Fagan/Patrick Luckow
Chapter 4	Generation Capacity Costs	Yakov Lasko
Chapter 5	Revenue Allocation	Cherie Chan
Chapter 6	Residential Rate Design	Lee-Whei Tan
Chapter 7	Small Commercial Rate Design	Peter Morse

QUALIFICATIONS OF
DAN WILLIS

Q.1. Please state your name and business address.

A.1. My name is Dan Willis. My business address is 505 Van Ness Avenue, San Francisco, CA 94102.

Q.2. By who are you employed and what is your job title?

A.2. I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst in the Electricity Pricing and Customer Programs Branch of the Office of Ratepayer Advocates (ORA).

Q.3. Please describe your educational background and professional experience.

A.3. I hold a Bachelor of Science degree in Environmental Economics and Policy from the University of California Berkeley. Since joining ORA in July of 2012, I have testified before the Commission in the Smart Meter Opt-Out Proceeding, A.11-03-014, and in Phase I of the Residential Rates Order Instituting Rulemaking (RROIR). I have also sponsored testimony in Phase II of PG&E's 2014 GRC and in Phase II of the RROIR. In addition, I have conducted detailed analysis on several other Commission proceedings on rate design, including the quasi-legislative portion of the RROIR and in PG&E's Application for an Economic Development Rate.

Q.4. What is your area of responsibility in this proceeding?

A.4. I am sponsoring Chapter 1 of ORA's prepared testimony, on Marginal Customer Costs.

QUALIFICATIONS OF
LOUIS IRWIN

Q.1 Please state your name and business address.

A.1 My name is Louis Irwin. My business address is 505 Van Ness Avenue, San Francisco, California 94102.

Q.2 By whom are you employed and in what capacity?

A.2 I am employed by the California Public Utilities Commission as a Regulatory Analyst in the Office of Ratepayers Advocates.

Q.3 Please describe your educational and professional experience.

A.3 I have a Master of Arts in Economics from the University of Colorado at Boulder with a focus on environmental, energy and urban issues and a Master of Public Administration from the JFK School of Government in Cambridge, Massachusetts. My thesis, while at C.U. Boulder, focused on natural resource scarcity and pricing. Both degrees included coursework in finance, economics and econometrics that I find relevant to this case. I also have a Bachelor of Arts in Psychology from U.C. Berkeley with a focus on organizational and business psychology applications. My senior project there involved a cost / benefit analysis that used calculus to solve for the inputs that would minimize overall turnover costs of a management training program. Since joining ORA in 1999, I have worked on a variety of energy related issues ranging from distributed generation to cost of capital cases. More recently, I have worked on marginal cost aspects of general rate cases and the Residential Rate OIR. Prior to coming to the Commission, I worked for seven years in economic consulting, regarding socio-economic impacts due to mining and energy facilities, including the proposed high-level nuclear waste site at Yucca Mountain, Nevada. My more recent consulting experience was directly in the energy field, performing productivity and comparative electric rate analyses with Christensen Associates of Madison, Wisconsin, a specialist in these areas.

Q.4 What is your area of responsibility in this proceeding?

A.4 I am sponsoring testimony for Chapter 2, Marginal Distribution Demand Cost

QUALIFCATIONS
OF
ROBERT M. FAGAN

Q1. Please state your name, position and business address.

A1. My name is Robert M. Fagan. I am a Principal Associate with Synapse Energy Economics, Inc., 485 Massachusetts Ave., Cambridge, MA 02139. I have been employed in that position since 2005.

Q2. Please state your qualifications.

A2. My full qualifications are listed in my resume, on the following pages. I am a mechanical engineer and energy economics analyst, and I have examined energy industry issues for more than 25 years. My activities focus on many aspects of the electric power industry, especially economic and technical analysis of electric supply and delivery systems, wholesale and retail electricity provision, energy and capacity market structures, renewable resource alternatives including on-shore and off-shore wind and solar PV, and assessment and implementation of energy efficiency and demand response alternatives.

I hold an MA from Boston University in Energy and Environmental Studies and a BS from Clarkson University in Mechanical Engineering. I have completed additional course work in wind integration, solar engineering, regulatory and legal aspects of electric power systems, building controls, cogeneration, lighting design and mechanical and aerospace engineering.

Q3. Have you testified before the CPUC before?

A3. Yes. I submitted pre-filed responsive testimony (jointly, with Patrick Luckow) in the San Diego Gas & Electric Rate Design Window (RDW) docket, Application 14-01-027, on November 14, 2014. I submitted pre-filed modeling rebuttal testimony in October 2014 in Docket R.12-06-013 (jointly, with Patrick Luckow). I submitted pre-filed modeling testimony in August 2014 in the 2014 LTPP docket (R.13-12-010; jointly, with Patrick Luckow). I also testified in Track 1 and Track 4 of the R.12-03-014 proceeding, and in the A.11-05-023, Application of San Diego Gas & Electric Company ((U902E) for Authority to Enter into Purchase Power Tolling Agreements with Escondido Energy Center, Pio Pico Energy Center and Quail Brush Energy Center. I have been involved in California renewable energy integration and related resource adequacy issues as a consultant to the ORA since the late fall of 2010. I have also testified in numerous state and provincial jurisdictions, and the Federal Energy Regulatory Commission (FERC), on various aspects of the electric power industry including renewable resource integration, transmission system planning, resource need, and the effects of demand-side resources on the electric power system.

Q4. On whose behalf are you testifying in this case?

A4. I am testifying on behalf of the California Public Utilities Commission's Office of Ratepayer Advocates (ORA).

QUALIFICATIONS
OF
PATRICK LUCKOW

Q1. Please state your name, position and business address.

A1. My name is Patrick Luckow. I am an Associate with Synapse Energy Economics, Inc., 485 Massachusetts Ave., Cambridge, MA 02139. I have been employed in that position since I started work at Synapse in 2012.

Q2. Please state your qualifications.

A2. I am an Associate at Synapse, with a special focus on calibrating, running, and modifying industry-standard economic models to evaluate long-term energy plans, and the environmental and economic impacts of policy/regulatory initiatives.

Prior to joining Synapse, I worked as a scientist at the Joint Global Change Research Institute in College Park, Maryland. In this position, I evaluated the long-term implications of potential climate policies, both internationally and in the U.S., across a range of energy and electricity models. This work included leading a team studying global wind energy resources and their interaction in the Institute's integrated assessment model, and modeling large-scale biomass use in the global energy system.

I hold a Bachelor of Science degree in Mechanical Engineering from Northwestern University, and a Master of Science degree in Mechanical Engineering from the University of Maryland.

Q3. Have you testified before the CPUC before?

A3. Yes. I submitted pre-filed responsive testimony (jointly, with Robert Fagan) in the San Diego Gas & Electric Rate Design Window (RDW) docket, Application 14-01-027, on November 14, 2014. I submitted pre-filed modeling rebuttal testimony in October 2014 in Docket R.12-06-013 (jointly, with Robert Fagan). I submitted pre-filed modeling testimony (jointly, with Robert Fagan) in August 2014 in the 2014 LTPP docket (R.13-12-010).

Q4. On whose behalf are you testifying in this case?

A4. I am testifying on behalf of the California Public Utilities Commission's Office of Ratepayer Advocates

QUALIFICATIONS OF
YAKOV LASKO

Q.1. Please state your name and business address.

A.1. My name is Yakov Lasko. My business address is 505 Van Ness Avenue, San Francisco, California, 94102.

Q.2. By whom are you employed and in what capacity?

A.2. I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst III in the Office of Ratepayer Advocates, Electricity Planning and Policy Branch.

Q.3. Please describe your educational and professional experience.

A.3. I received a Bachelor of Arts Degree in Political Economy of Industrial Societies from the University of California, Berkeley. I also possess a Master of Science Degree in Corporate Finance from SDA Bocconi School of Management located in Milan, Italy. I joined the Commission on January 3, 2012 in ORA's Electricity Planning and Policy Branch. At present, I am involved in ERRA Compliance, Joint Reliability Plan OIR, Resource Adequacy and SCE's GRC Phase II application.

Q.4. What is your area of responsibility in this proceeding?

A.4. I am sponsoring Chapter 4 of ORA testimony, which presents ORA's policy on Marginal Generation Capacity Costs.

QUALIFICATIONS OF
CHERIE CHAN

Q.1. Please state your name and business address.

A.1. My name is Cherie Chan. My business address is 505 Van Ness Avenue, San Francisco, CA 94102.

Q.2. By whom are you employed and what is your job title?

A.2. I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst in the Electricity Pricing and Customer Programs Branch of the Office of Ratepayer Advocates.

Q.3. Please describe your educational background and professional experience.

A.3. I hold a Bachelor of Arts degree from the University of California at Berkeley, with a major in Social Welfare and minors in Business and Demography. I have worked as a Billing Analyst at PG&E and as Manager of the Billing Department at Utility.com. At ABB Inc., I helped implement Interval Data Software products for utilities as a Project Manager and Product Engineer. I joined the Commission in 2005 and have sponsored Marginal Cost, Rate Design and AMI testimony, departing in 2007 to manage marketing and product management of smart grid programs at eMeter and Oracle. I returned to The Commission in 2009 and have continued to testify in rate design and other proceedings.

Q.4. What testimony are you sponsoring in this proceeding?

A.4. I am sponsoring Chapter 7 of ORA's prepared testimony on the rate design proposals' impacts on energy efficiency, demand response, and distributed generation programs and Chapter 8 of ORA's prepared testimony on education and outreach on behalf of Michaela Flagg.

QUALIFICATIONS OF

LEE-WHEI TAN

Q.1. Please state your name and business address.

A.1. My name is Lee-Whei Tan. My business address is 505 Van Ness Avenue, San Francisco, CA 94102.

Q.2. By who are you employed and what is your job title?

A.2. I am employed by the California Public Utilities Commission as a Regulatory Analyst V in the Electric Pricing and Consumer Program Branch of the office of Ratepayer Advocates ("ORA").

Q.3. Please describe your educational background and professional experience.

A.3. I received a Bachelor of Science Degree in Chemistry from National Tsing Hua University in 1979 (Taiwan) and a Master of Arts Degree in Economics in 1986 from San Francisco State University.

In July 1986, I joined the Fuels Branch of the Division of Ratepayer Advocates where I sponsored testimony relating to utilities fuel management practices. I transferred to the Special Economics Branch in July 1987 and was involved in the benchmarking of computer programs (ELFIN, PCAM, PROMOD). In April 1988, I joined the Economics and Energy Rate Design Branch where I was assigned marginal costs and rate design for gas and electric cases. In 2001, I was assigned to the Telecommunications Branch of ORA, where I was assigned to work on telephone utility cases, such as New Regulatory Framework proceedings, mergers, and Public Utilities Code §851 proceedings.

I joined the Electric Pricing and Consumer Program Branch in July, 2009, and have been assigned to work on the revenue allocation and project coordination for San Diego Gas and Electric ("SDG&E") Critical Peak Pricing Application and the IOUs' (Pacific Gas and Electric Company's ("PG&E"), Southern California Edison ("SCE"), SDG&E) GRC Phase 2 Filings as well as recent Residential Rate reform OIR 12-06-013.

Q.4. What is your area of responsibility in this proceeding?

A.4. I am sponsoring Chapter 6, Residential Rate Design.

QUALIFICATIONS OF

PETER MORSE

Q.1 Please state your name and business address.

A.1 My name is Peter H. Morse. My business address is 505 Van Ness Avenue, San Francisco, California 94102.

Q.2 By whom are you employed and in what capacity?

A.2 I am employed by the California Public Utilities Commission as a Public Utilities Regulatory Analyst in the Office of Ratepayer Advocates, Energy Cost of Service and Natural Gas Branch.

Q.3 Please describe briefly your educational background and work experience.

A.3 I have a Bachelor of Science degree in Agricultural Business, with a minor in Sustainable Environments, from California Polytechnic State University San Luis Obispo.

Prior to joining the Commission, I was employed by the Utility Consultants of California as an Associate Analyst, where I was responsible for quantitative analysis of water and energy consumption data, analysis of water conservation data and creating/formatting workpapers filled before the CPUC.

Since joining the Commission in June 2012, I have sponsored testimony before the Commission in West Coast Gas Company's TY 2013 General Rate Case (GRC), PG&E's TY 2014 GRC and SCE's TY 2015 GRC.

Q.4. What is your area of responsibility in this proceeding?

A.4. I am sponsoring Chapter 7 of ORA's testimony, Small Commercial Rate Design.